

**THE IMPACTS OF INCREASED LEVELS OF  
WIND PENETRATION ON THE ELECTRICITY  
SYSTEMS OF THE REPUBLIC OF IRELAND AND  
NORTHERN IRELAND: FINAL REPORT**

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## CONTENTS

		<b>Page</b>
	<b>Executive Summary</b>	<b>1</b>
<b>1</b>	<b>INTRODUCTION</b>	<b>7</b>
1.1	Background	7
1.2	This Study	8
1.3	Acknowledgements	9
1.4	Glossary	9
<b>2</b>	<b>TASK 1: ESTABLISHING THE BACKGROUND</b>	<b>11</b>
2.1	Previous Experience	11
2.1.1	Penetration levels	11
2.1.2	Ensuring generation adequacy	14
2.1.3	The planning of the power system	14
2.1.4	Operation of the power system – Power and energy balance	15
2.1.5	Operation of the power system - Transmission	16
2.2	New developments	17
2.2.1	Impact of very large wind farms	17
2.2.2	Impact of sophisticated controls	17
2.2.3	Wind energy power plants	18
2.3	Wind Turbine Types	19
2.4	Review of Grid Codes	19
2.4.1	Power cap	20
2.4.2	Rate of change of power: positive	20
2.4.3	Rate of change of power: negative	21
2.4.4	Other power control	21
2.4.5	Frequency regulation	21
2.4.6	Operating voltage and frequency range	22
2.4.7	Reactive power and voltage control	22
2.4.8	Transient stability (‘fault ride through’)	22
2.4.9	Summary of review of grid codes	23
2.5	Frequency Reserve	24
2.6	Wind Forecasting	25
2.6.1	Forecasting techniques	25
2.6.2	Forecast uncertainties	27
2.6.3	Forecasting requirements	27
2.6.4	Forecasting capabilities	28
2.6.5	Implications for the RoI and NI systems	29
2.7	Wind Variability	30
2.8	Incidence of Calms, and Capacity Credit	32

2.9	Views of Interested Parties	34
2.9.1	Discussions with Regulators	34
2.9.2	Discussions with system operators and planners	35
2.9.3	Discussions with the wind industry	36
2.10	Characteristics of Project Developers in RoI and NI	37
2.11	Administration and Business Process Issues	37
2.12	Summary	39
<b>3</b>	<b>TASK 2: WIND RESOURCE &amp; WIND FARM LOCATION</b>	<b>41</b>
3.1	Previous Work	41
3.1.1	Onshore wind	41
3.1.2	Offshore wind	44
3.2	Work Underway	45
3.3	Policy Considerations	45
3.3.1	Background	45
3.3.2	Recent policy developments	47
3.4	Summary	49
<b>4</b>	<b>TASK 3: DISTRIBUTION SYSTEM CONSTRAINTS</b>	<b>50</b>
4.1	Introduction	50
4.1.1	ESB system	50
4.1.2	NIE system	50
4.2	Characteristics of Networks in Likely Areas	50
4.3	Steady-state Voltage Range and Voltage Control	50
4.4	Thermal Ratings	51
4.5	Reverse Power through Tapchangers	51
4.6	Protection	51
4.7	Power Quality	52
4.8	Fault Levels	53
4.9	Constraining Wind Generation	53
4.10	Resource Issues	53
4.11	Need for Distribution System Reinforcement	54
4.12	Summary	55
<b>5</b>	<b>TASK 4: TRANSMISSION SYSTEM LIMITS</b>	<b>57</b>
5.1	Methodology for Study of Transmission System Limits	57
5.2	Results of Study of Transmission System Limits	58
5.2.1	Target year 2005	58
5.2.2	Target year 2007	59
5.2.3	Target year 2010	59
5.3	Location	59
5.4	Discussion	66

<b>6</b>	<b>TASK 5: IMPACT ON POWER SYSTEM OPERATION AND ANCILLARY SERVICE COSTS</b>	<b>69</b>
6.1	Voltage Stability	69
6.2	Frequency Regulation and Reserve Requirements	70
6.2.1	Effect of wind generation on reserve requirements	70
6.2.2	Contribution to reserve requirements	72
6.3	Power Quality	73
6.4	Dynamic Issues	73
6.5	Ancillary Services	74
6.5.1	Black start	74
6.5.2	Reserve	74
6.5.3	Frequency regulation	74
6.5.4	Fault current	74
6.5.5	Costs of ancillary services	75
6.6	Interconnectors	75
6.7	Storage	76
6.8	Summary	76
<b>7</b>	<b>TASK 6: ECONOMIC FACTORS</b>	<b>77</b>
7.1	Economic Effects	77
7.1.1	Curtailment	78
7.1.2	Fuel savings	80
7.1.3	Grid Code changes	81
7.1.4	Forecasting	82
7.1.5	Remedial action schemes	82
7.1.6	Ancillary services	83
7.1.7	Losses	83
7.1.8	Capacity credit	84
7.1.9	Effect on other generators	84
7.1.10	Summary of effects on costs	84
7.2	Ilex/UMIST report	86
7.3	Trading Arrangements	87
<b>8</b>	<b>CONCLUSIONS AND RECOMMENDATIONS</b>	<b>90</b>
8.1	Principal Conclusions and Recommendations	90
8.1.1	Wind turbine technology and network operator requirements	90
8.1.2	Feasible wind capacity on the combined systems	92
8.1.3	Forecasting and operational data	95
8.1.4	Capacity credit and operating strategy	96
8.1.5	Administrative matters	97
8.2	Key Questions	97
<b>9</b>	<b>REFERENCES</b>	<b>101</b>

**APPENDIX 1: Summary terms of reference**

**APPENDIX 2: Comparison with NIE/DETI study**

**APPENDIX 3: Methodology for Task 4, Transmission System Limits**

**APPENDIX 4: Fluctuation of Wind Farm Power Output and Incidence of Calms**

**APPENDIX 5: Incidence of calms: Met Éireann data**

**APPENDIX 6: Comparison of transmission system limits with Forecast  
Statement for 2005**

**APPENDIX 7: Trading arrangements**

## Executive Summary

This study was commissioned by the Commission for Energy Regulation and Ofreg in order to explore further the effects of increasing levels of wind energy generation on the combined electricity systems of the Republic of Ireland (RoI) and Northern Ireland (NI). The study has been based on three 'target years': 2005, 2007 and 2010. Detailed terms of reference are in Appendix 1.

The aims of this work are to review the likely effects of high wind penetration on the combined electricity systems, identify those issues which may limit the ability of the two jurisdictions to achieve their stated aims for renewable electricity generation, and determine potential courses of action with appropriate timescales. This is primarily a technical study, and it is important to realise that there are no absolute technical limits on the wind generating capacity which may be connected to the combined systems: all technical issues are soluble at some cost. These costs could be high. It is therefore important to determine the factors which will have a major effect on costs.

For clarity, the major results and conclusions are described below in a series of 'topics'. Each important assumption is introduced at the appropriate point. More detailed conclusions are presented in the body of this report.

### ***Treatment of conventional generation***

The term 'conventional generation' is used in this study to describe thermal plant such as fossil-fired steam plant or gas turbines. An underlying assumption in the terms of reference of this work is that in any target year, the capacity of conventional generation which would exist in the absence of wind generation is not reduced by the addition of wind.

In addition to energy, power systems need 'ancillary services', such as provision of reactive power, reserve capacity, and control of system frequency. These functions are provided by conventional generation, but some can also be provided by wind generation. This is discussed in a separate topic below, where it is noted that wind generation is particularly unsuited to providing the reserve and frequency response functions.

It was decided to adopt the principle that at any time, the conventional generation that would run if there was no wind generation on the system will also run when wind generation is connected. As the output of wind generation is increased, the output of the conventional generators will be reduced accordingly, but no conventional generation will be shut down. This principle is costly at high wind penetrations, as it requires conventional generation to run at low output, at lower thermal efficiency. For the same reason, the emissions savings resulting from the wind generation are less than could otherwise be achieved. These factors are quantified in the report.

In this way, the reserve and frequency response functions continue to be provided by the conventional generation. This simplifies the analysis, as it is not necessary to determine and cost alternative means of providing these functions. In reality alternative means are available and may offer cost benefits. Therefore this should be seen as a conservative simplifying assumption.

In addition, with this assumption it is not necessary to make further assumptions about the accuracy of wind forecasts, as it will always be possible to increase the output of the conventional generation rapidly (i.e. over periods of a few hours) in the event of wind speeds decreasing unexpectedly.



This principle is commonly called the ‘fuelsaver’ option, as the only benefit of wind generation is to save fuel otherwise consumed by conventional generation.

It is very likely that in reality, and with experience, the capacity of conventional generation operating at any time can be reduced. The remaining conventional generation can then run closer to its optimum efficiency. This depends principally on confidence in wind forecasting (i.e. how much reliance can be placed on wind generation), and on the ability of wind farms to meet the transmission system operators’ technical requirements (discussed as a separate topic below). This will save fuel but increase the frequency with which conventional generators are started and stopped.

It is recommended that alternative, less conservative operating strategies are studied in the near future, so that preferred strategies can be in place before wind penetration reaches a level where the economic penalties of the conservative approach are significant.

It is also likely that changes to the conventional generation mix will offer savings. As noted above, an underlying assumption of this work is that the conventional generation available in the target years is as currently foreseen. With high wind penetration there will be advantages in having conventional generation which can change its output more rapidly, can start and stop more rapidly, and has lower costs in a regime of greater variability. This may influence the choice of new generating capacity required, or could lead to modifications to existing generators. These considerations should be included in any study of alternative operating strategies.

#### ***Abilities of wind generators, and system operators’ technical requirements***

Traditionally, wind turbines have been treated as ‘negative load’, i.e. they provided energy to the power system but nothing else. In some cases they created additional problems for the power system. They were connected to distribution systems, and their effect on the electrical system as a whole was small enough to be ignored. In addition, system operators were not familiar with wind technology, and their technical requirements were written on the basis of conventional generation. Wind farms could not meet all these technical requirements, and were often excused from doing so.

Facing the twin prospects of large wind farms connected to the transmission system, and high total wind capacity, possibly displacing conventional generation, system operators are attempting to define technical requirements for wind farms through formal routes such as ‘Grid Codes’. The current state of these requirements for several jurisdictions was reviewed in this study. This study has reached the following conclusions.

- Most of the likely requirements can be met by variable-speed wind turbine technology, with some costs in terms of development effort and additional control and communications capability. These costs will have an insignificant effect on cost of energy from wind generation.
- Fixed-speed wind turbines, and in particular stall-regulated wind turbines, are likely to face higher costs to meet these requirements than variable-speed wind turbines. However Grid Codes should be written in terms of technical requirements for wind farms, rather than preferred technologies.
- Requirements for provision of frequency response and reserve could be met by wind generation but at high cost. For economic efficiency these functions could be provided by conventional generation, perhaps through a market mechanism.

- A process of discussion on the form and content of Grid Codes is required in all affected jurisdictions (this is already in train in several), and Regulators may wish to facilitate this.
- Wind turbine manufacturers now see grid codes and related issues as important and are working on these issues.
- There could be an economic case for small wind farms being excused some of the requirements, especially those (such as communications) which are proportionately more expensive for small projects, with perhaps some system-wide limit on the total capacity of wind generation treated in this way.

It is therefore assumed in this study that wind turbines are likely to be available by 2005 which can meet the agreed Grid Code requirements at an additional cost which is insignificant compared to total project costs. Under this assumption, and the treatment of conventional generation described above, there is no need to build additional plant, for example for provision of reactive power or frequency response.

If the assumption in the above paragraph does not hold true, there is a substantial risk to the targets for renewable generation in both jurisdictions. Therefore it is recommended that the Regulators and the system operators keep abreast of progress by the wind industry, so that delays or problems which may threaten the targets are identified early.

### ***Limits on capacity of wind generation***

The study found that there were two fundamental types of factors which limit the capacity of wind generation that can be connected to the combined systems:

- transmission planning criteria (referred to here as *Type 1*);
- curtailment of wind production due to the requirement to continue to run conventional generation (*Type 2*).

The Type 1 effect is explained as follows. Under existing transmission planning criteria, all generation must be considered as 'firm', i.e. it must be able to continue to operate in the event of any one of a defined set of 'contingencies' on the transmission system. The list of possible contingencies is complex, but for simplicity in this study they are divided into two types:

- 'N-1', where one element of the transmission system is unavailable (for example, a fault on a transmission line or other element of the transmission system, such as a transformer);
- 'N-2': more complex, less frequent contingencies, such as the failure of an element when another element is removed for maintenance.

Note that the terms N-1 and N-2 are used here for simplicity and do not strictly agree with the terminology used by the TSOs. The important point in this context is a distinction between the most common and less common contingencies.

To cope with these contingencies, transmission systems are designed to be highly robust, with multiple parallel paths. Any new generation project may require transmission system reinforcement in order to ensure that it can be considered as 'firm'. This principle is currently followed by system operators and contributes to the extremely high levels of reliability exhibited by modern power systems.

An alternative approach, which is a departure from present principles, is to treat wind generation as 'non-firm', i.e. the system will survive the loss of this generation in the event of a contingency. Through a concept called (for want of a better term at present) a Remedial Action Scheme (RAS), transmission reinforcement can be delayed, or possibly avoided altogether. The RAS principle is discussed as a separate topic below.

The Type 2 effect is a corollary of the principle explained above (*Treatment of conventional generation*). As the output of wind generation is increased, the output of the conventional generation running at the time is reduced. Eventually the conventional generation will reach a limit below which its output cannot be reduced, for technical reasons. When this limit is reached, the output of the wind generation must be reduced ('curtailed') instead. This curtailment clearly has economic consequences.

It was found that the two types of limit have the following effects, which are best understood by considering the consequences of increasing the wind capacity from its current level.

- **Limit A (Type 1).** As wind capacity is increased, a point is reached where it becomes necessary to reinforce the transmission system in order to meet the transmission planning criteria for N-2 contingencies. This is a location-specific issue: there are a number of locations at which wind generation may be connected without requiring transmission system reinforcement in order to meet the N-2 contingencies requirement. When those locations are 'full', further projects will cause system reinforcement. It is important to note that this study did not examine Limit A, as the consideration of N-2 effects requires a large number of location-specific studies. However a similar study is contained within the latest ESB National Grid Forecast Statement, where a number of nodes on the 110 kV transmission system were examined for their ability to accept more or less than 100 MW of new generation. On this basis it is concluded that on the combined systems Limit A occurs at well under 1000 MW of total wind capacity, probably at a few hundred MW. If this point needs to be defined more closely (which depends on the decisions reached about RAS), then the transmission system operators should be asked to expand the methodology in the ESB National Grid Forecast Statement.
- **Limit B (Type 2).** At approximately 800 MW of wind capacity in 2005 (approximately 1000 MW in 2007 and 2010), wind curtailment is first required. This will occur when full output from the wind generation coincides with low demand periods (i.e. summer nights). Therefore the effect is initially very small in economic terms: however, it will be important to have in place the necessary control infrastructure, and the frameworks under which curtailment will be administered, before this point is reached.
- **Limit C (Type 1).** At approximately 3300 MW of wind capacity, there are no locations left on the transmission systems at which wind generation can be connected without requiring transmission system reinforcement to meet the N-1 contingencies.
- **Limit D (Type 2).** At approximately 4000 MW of wind generation, the curtailment of the last wind turbine will be such that it will operate for only a few hours per year, near the times of system maximum demand. Clearly this would be uneconomic, and hence this figure of 4000 MW is of theoretical rather than practical importance. The report contains an analysis of the effect of curtailment on wind farm capacity factor from Limit B to Limit D.

These conclusions are believed to be relatively insensitive to the location of wind generation. It was found possible to connect the wind capacities stated above to the 110 kV system or below, but similar capacities were also found when appropriate nodes on the 220 and 275 kV systems were considered as an alternative.

#### ***Non-firm wind generation and the RAS principle***

The RAS principle would allow transmission reinforcement to be delayed, with significant cost savings, or possibly even avoided. In the context of the targets for the two jurisdictions, the avoidance of delay is possibly as important as cost. It is relevant for Limits A and C above.

RAS has been adopted in other countries to defer the need for transmission system reinforcement, notably in the US where it has been used for wind farm connections.

RAS would be implemented by automatic protection equipment, which would detect the occurrence of particular contingencies and automatically disconnect the wind generation in the area. This study found that, for any particular location, the number of such contingencies to be detected was small, so that the cost, reliability and extent of the RAS should be acceptable. It is likely that, in many cases, all equipment could be located within one substation.

If the capacity of the wind generation that would be lost due to any one contingency is less than the size of the maximum system infeed, currently about 400 MW, then the system will be able to cope with this disturbance without increasing the need for reserve.

The incidence of such events must be low enough that the possibility of two calls on the system reserve occurring at one time remains acceptably small. This requirement appears to be realistic.

The RAS concept is a departure from current principles. However the potential benefits are substantial, and hence it is recommended that it is considered by the Regulators and the transmission system operators and planners in the near future.

### ***Forecasting***

It is concluded that forecasting of the output of wind generation is important. Although already in use by some system operators, it can still be considered a research area. Under the principles outlined above, its value is economic, i.e. accurate forecasting will allow less conservative operating strategies to be adopted. It seems clear that the economic benefits of better forecasting will easily outweigh its cost.

### ***Capacity credit***

The study found conflicting evidence for the value of wind generation in providing capacity. It is clear that there will be occasions, possibly several times per year, when there is no or very little output from all wind generation on the island at times of high electricity demand. It also appears that in these circumstances there will often be little output from wind generation in preferred wind areas in Scotland and Wales, so the economic case for interconnectors to these areas on this justification alone is weak.

However, other detailed studies have shown some capacity credit, with significant economic value to wind projects.

This study has taken the conservative view that wind has no capacity credit, but it is recommended that this be studied further. The methodology adopted in the latest ESB National Grid Generation Adequacy Report appears sound, but needs repeating with more extensive data.

For this reason, and for other similar reasons, recommendations are made for comprehensive collection of data from operating wind farms, to be started as a priority.

***Conclusion***

This work has provided answers to some of the technical questions being discussed by the wind industry and system operators. It has also identified some technical issues that need further work to resolve. None of the technical issues are considered insuperable.

The major cost elements are:

- Transmission reinforcement, starting at Limit A and Limit C as defined above, unless the RAS principle is adopted.
- Wind curtailment, starting at Limit B.
- Capital and operating costs for wind generation, including network connection.

Depending on the aims of any economic analysis, the last item can be replaced by the difference between the selling price of wind and the selling price of conventional generation.

Against this must be set the savings in conventional fuel consumption. These savings decrease in relative terms as wind capacity increases, because the conventional generation is forced to operate further from its optimum efficiency.

## 1 INTRODUCTION

### 1.1 Background

Wind energy deployment is relatively new in RoI and NI, particularly when compared to other E.U. Member States such as Germany or Denmark. The first commercial wind farm of 6.45 MW installed capacity was commissioned in 1992. Development remains relatively modest, with 30 wind farms currently in operation. These represent a combined installed capacity of 173 MW, compared with a total generating capacity on the island of over 6,500 MW. Wind energy currently contributes about 1.5% of RoI and NI's electricity demand and 2.4% of generating capacity.

It is anticipated that significant accelerated growth in the deployment of wind energy will occur in the short to medium-term as evidenced by ambitious targets and the amount of activity in the market in on-shore and off-shore wind energy (summarised below). The impacts of this growth in intermittent generation on the electricity network have prompted this study.

In the **Republic of Ireland**, the *Green Paper on Sustainable Energy* (in 1999) set a target for renewable energy of an additional 500 MW installed capacity by 2005, most of which is anticipated to come from on-shore wind energy. The *EU Directive on the Promotion of Electricity from Renewable Energy* (2001) detailed indicative targets for each of the Member States for 2010. In the Republic of Ireland's case, the target for electricity produced by renewable energy in 2010 is 13.2% of gross electricity consumption. This would require an additional target of approx. 400 MW from renewable energy for the period 2005-2010. If this all is provided by additional wind farms, then wind generated electricity will contribute **10.4% of the Republic's electricity needs** by 2010. In October 2002, the Minister for Communications, Marine and Natural Resources stated that the government intended surpassing the EU indicative target. This emphasises the statement contained in the National Climate Change Strategy that "*significant further expansion will be required....having regard inter alia to targets at EU level.*"

In February 2002 the Department of Public Enterprise, (now the Department of Communications, Marine and Natural Resources), published details of wind farms with a combined installed capacity of 354 MW that had secured Power Purchase Agreements under the AER V scheme. These projects will mark the first significant step in reaching the 500 MW target by 2005. This was followed in November 2002 with a Ministerial announcement on details of the AER VI competition. The allocation for wind energy is 470 MW – 350 large-scale, 70 MW small-scale and 50 MW offshore. It is important to note that projects bid into AER V can re-bid into AER VI, subject to a number of conditions.

Activity in the market place indicates plans for wind farms with a cumulative capacity of **approximately 2,000 MW on-shore and a further 2,000 MW off-shore**. By November 2001, wind farms with a combined installed capacity of 363 MW had secured planning permission and a further approximately 500 MW were within the planning process awaiting a decision. It was estimated that additional applications for planning permission for wind farms would be submitted before the end of 2002 for a further approximately 1,500 MW. Regarding off-shore wind energy, foreshore licenses have been issued for 7 sites, mostly on the East Coast. To date one foreshore lease has been issued for a proposed 520 MW wind farm. Based on information available from the developers, the combined capacity may be as high as 2,000 MW.

In **Northern Ireland**, the Department of Enterprise, Trade and Investment (DETI) are currently considering renewables strategy and targets. Recommendations under consideration include those of the Committee for Enterprise Trade and Investment Report on the Energy Inquiry for an implementation plan be established to meet a target of 15% of electricity demand from renewable energy by 2010. It further recommends the establishment of a Renewable Energy Obligation, as exists in Great Britain. The UK Crown Estate has initiated a competition to bid for the option to develop a 150 – 250 MW wind farm off the coast of Portrush, County Derry.

An assessment has been made of the likely expansion of wind generation on the island of Ireland, to aid in providing a context for subsequent elements of this study.

## 1.2 This Study

The Commission for Energy Regulation (CER) in the Republic of Ireland, in co-operation with the Office for the Regulation of Electricity and Gas (OFREG) in Northern Ireland, commissioned Garrad Hassan (GH) to undertake this study of the effects of increased levels of wind penetration on the electricity system of the island of Ireland. The Terms of Reference are summarised in Appendix 1.

The work was led by GH, with ESBI and the Sustainable Energy Research Group of University College Cork as subcontractors.

The clients' requirements are best summarised by the key questions listed in the original Request for Tenders.

1. *What is the feasible level of wind penetration, which can be safely and securely accommodated given the existing RoI and NI transmission systems and plans for their reinforcement?*
2. *How is this level determined at the moment by the respective transmission system operators?*
3. *What are the potential impacts of increased wind generation on system reliability and power quality?*
4. *What are the economic costs and benefits of accommodating increased wind generation?*
5. *What are the potential impacts of increased wind generation, in terms of both price and quality of supply, on final customers?*
6. *Are there any other factors, which will potentially impact on the ability of the system to handle increased amounts of wind generation?*

The work was organised into several tasks:

- Task 1: establishing the background
- Task 2: wind resource and wind farm location
- Task 3: distribution system constraints
- Task 4: transmission system limits
- Task 5: impact of wind penetration on power system operation and ancillary service costs
- Task 6: economic factors
- Task 7: reporting and deliverables.

This report is structured in accordance with the above tasks, modified where necessary for clarity and to take account of changes in emphasis that emerged during the work.

The first interim report covered Tasks 1 and 2 of the agreed programme of work [1]. It was produced to provide an opportunity for interested parties to understand the intended work and methodology, and to comment on the background established in Tasks 1 and 2. Comments were received from several parties, which resulted in further discussions and some modifications, which have been incorporated in this report.

### 1.3 Acknowledgements

Garrad Hassan wishes to thank the project partners, ESBI and the Sustainable Energy Research Group at UCC, for their major contributions to this study.

GH also wishes to thank:

- ScottishPower for provision of wind farm operating data analysed in Section 5
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- staff at ESB National Grid and SONI/NIE for their co-operation and useful comments.

### 1.4 Glossary

<b><i>RoI</i></b>	Republic of Ireland
<b><i>NI</i></b>	Northern Ireland
<b><i>GB</i></b>	Great Britain (the UK minus Northern Ireland)
<b><i>DSO</i></b>	Distribution System Operator
<b><i>TSO</i></b>	Transmission System Operator
<b><i>ESB National Grid</i></b>	The TSO in the RoI, now being replaced by Eirgrid
<b><i>SONI</i></b>	System Operator of Northern Ireland. Responsible for both transmission and distribution system operation.
<b><i>NIE</i></b>	Northern Ireland Electricity. The Transmission and Distribution (T&D) business is the owner of the NI system, with responsibility for system planning in conjunction with SONI.

#### ***Fixed-speed wind turbine***

Rotates at almost constant speed, because the generator is directly connected to the fixed-frequency electricity network. Sometimes provided with a second fixed speed (lower), to give them better energy capture on low-wind sites.

#### ***Variable-speed wind turbine***

Rotates at a higher speed in higher winds, so that the rotor operates close to peak aerodynamic efficiency over most of the operating range. Variable-speed operation is achieved by providing a power electronic converter to connect the variable-frequency output of the generator to the fixed-frequency electricity network. This power electronic converter can also provide control of power factor.

#### ***Direct-drive***

For variable-speed turbines only. The wind turbine has a low-speed generator directly connected to the wind turbine rotor, removing the need for a speed-increasing gearbox. In this case all the output power flows through the power electronic converter.



***Doubly-fed induction generator (DFIG)***

For variable-speed turbines only. Also known as the wound-rotor induction generator. Here the stator of the generator is directly connected to the fixed-frequency electricity network. The rotor circuit is connected via a power electronic converter, which therefore only has to handle about 30% of the output power, and is correspondingly smaller, cheaper and more efficient.

***Pitch-regulated wind turbine***

The blades can be rotated about their longitudinal axis to control the aerodynamic torque, for control of output power and for braking.

***Stall-regulated wind turbine***

The blades are fixed at an angle such that in high winds aerodynamic stall occurs, limiting the power generated.

***Active stall***

As for stall regulation, but the blades can be rotated, slowly and over a small angular range, so that the same power/wind speed characteristic can be maintained irrespective of air density and blade fouling.

***Power factor***

A measure of the reactive power at a point on the power system, or produced or consumed by an element of the power system.

***Reactive power***

A complex concept used by electrical engineers. Reactive power represents energy that flows between inductive and capacitive impedances, but without transmitting any energy from generators to consumers. Most elements of a power system (such as cables, overhead lines, transformers, loads, and generators) have such impedances, and are said to 'consume' or 'produce' reactive power. The reactive power flows in a power system create currents that contribute to the total system electrical losses, and so reactive power has economic value. Reactive power flows also affect voltage, and in many cases this is a more important effect than the electrical losses. Reactive power can be controlled by suitable design, including additional plant. Conventional synchronous generators can be controlled to produce or consume reactive power. Induction machines, common in fixed-speed wind turbines, can only consume reactive power, and therefore such wind turbines are often fitted with 'power factor correction' equipment.

## 2 TASK 1: ESTABLISHING THE BACKGROUND

Prior to undertaking the modelling reported in later Sections, this task was concerned with establishing the present state of affairs, in the two Irish jurisdictions and abroad. An interim report detailing information gathered for this task was released, and comments invited [1].

### 2.1 Previous Experience

This section describes reported operational experience and research findings.

#### 2.1.1 Penetration levels

The following definitions are useful, and may vary slightly from similar definitions used elsewhere.

- **Installed capacity penetration:** this is the installed wind generation capacity (in MW) connected to an electrical system, normalised by the capacity of all generation installed on that system.
- **Power penetration:** this is the output of the wind generation (in MW) at a given time, normalised by the system demand at that time.
- **Energy penetration:** this is the electricity produced by the wind generation, normalised by the gross electricity consumption in the electrical system, usually on an annual basis.

It is important to know which concept is meant when ‘wind penetration’ is being discussed.

The development of wind power in the last 25 years is a story of progress from small-scale experimental machines, used to prove the concept, to large-scale wind farms commissioned as entirely commercial ventures. Power systems across the globe, but mainly western Europe, the US and India, have accommodated wind power, initially on distribution systems and latterly, with the advent of large-scale wind farms, on transmission systems. This process of accommodation, which has continually given rise to technical and economic challenges that power system engineers and project developers have had to overcome, continues today with the creation of off-shore wind farms.

The growth of wind power on the island of Ireland has, to date, been relatively modest, with 30 wind farms with approximately 173 MW in operation. Of this only 15 MW is connected to the transmission system, with the overall production capacity on the island being in excess of 6500 MW. This represents an installed capacity penetration of 2.4 %. Given the abundance of the wind resource available in RoI and NI, the decreasing costs of the technology and ‘green’ dividend associated with such energy, this low growth situation is unlikely to persist.

If the renewable energy strategy being promulgated by both jurisdictions is successful the installed capacity penetration is predicted to rise to approximately 16% by 2010, as shown in Table 2.1. This table is based on Government targets in RoI or recommendations in NI which are expected to result in wind producing approximately 10 % of electricity production in 2010. The required wind capacity is then calculated assuming an average capacity factor of 0.35. It should be noted that the total generation capacity forecasts used in the table are forecasts based on ‘business as usual’, i.e. that the addition of wind on to the system does not decrease the conventional generation capacity. At high wind penetrations, this assumption may not hold true. In this case, the capacity penetrations shown in the table would increase.

Note also that the figures for the Republic of Ireland system in 2010 will not meet the generation adequacy standard, and so greater generation capacity may be needed than is shown here.

Item	Island of Ireland (2001)	RoI (2010)	NI (2010)	Island of Ireland (2010)	Eltra system, DK (2001)	Crete system (2001)
<b>Total conventional generation capacity [MW]</b>	6,500	5,067	2,012	7,079	4,724	570
<b>Total wind capacity [MW]</b>	162	1,042	351	1,393	1,932	70 (plus 54 MW expected in 2003)
<b>Total generation capacity, including wind [MW]</b>	6,662	6,109	2,363	8,472	6,656	640
<b>Installed wind capacity penetration</b>	2.4 %	17.1 %	14.9 %	16.4 %	29.0 %	10.9 %
<b>Wind energy penetration</b>	1.5 %	10 %	10 %	10 %	16.2 %	10 %
<b>Transmission capacity to other networks [MW]</b>	450	n/a	n/a	450	950 (DE), 1040 SE), 650 (NO) = 2,640	0

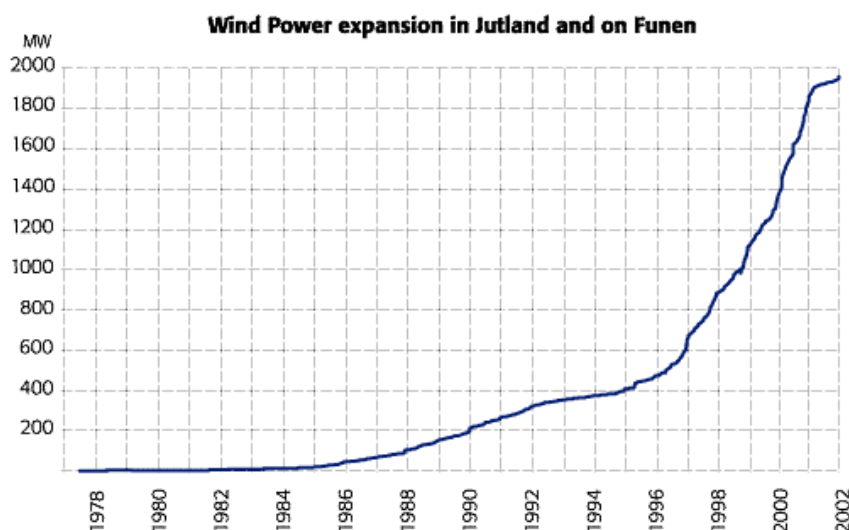
**Table 2.1: Comparison of forecast wind penetration in RoI and NI with Eltra and Crete systems**

One power system that has coped with significant penetration of wind power is the Danish system. For comparison, the data for Eltra, the Transmission System Operator (TSO) for the western part of Denmark, are also shown in Table 2.1. It can be seen that the forecast for RoI and NI in 2010 is, on paper, less onerous than the current situation in the Eltra area. However, it is important to note that the Danish system differs from the RoI and NI systems in having significantly more interconnections to neighbouring systems. This has a major effect, providing an ability to compensate for high levels of wind penetration through an additional source of both energy and ancillary services.

However, the connection to Germany is becoming limited in value because of the high penetration of wind power in northern Germany. This means that when there is surplus wind production in Denmark, the transmission capacity to Germany is often limited below the figure given in the table. The transmission capacity to Norway and Sweden is much more significant, especially as these systems are dominated by hydro generation.

The other major factor is the ‘non-dispatchable’ nature of wind generation and heat-led CHP plants in Denmark, i.e. plants whose output cannot be controlled in any way by the system operator, and whose output must be accepted onto the system. In addition to the 1,932 MW of wind generation, there is also 1,560 MW distributed CHP plant, all of which is, for political reasons, non-dispatchable. This is causing significant difficulties for the Danish system operators at the penetration levels shown in Table 2.1 [26]. Approximately half the generating capacity is non-dispatchable. If this ‘bound production’ was dispatchable, the interconnection issue would become less important. Equally, if the Eltra system had fewer interconnections, the non-dispatchable generation would have made the system inoperable before now and precipitated changes to the financial and operational framework. There is therefore an issue for the RoI and NI systems: is it necessary that wind generation can be dispatched (i.e. curtailed) by system operators? And if so, who suffers the financial effect of the lost production? This is addressed later in this report.

The historical growth in wind power in western Denmark is shown graphically in Figure 2.1. This exponential growth in wind power is challenging for system operators and planners. The rates of growth are similar to those expected in RoI and NI



**Figure 2.1: Wind power expansion in Jutland and Funen (Eltra area)**

It is instructive to examine the challenges faced by systems such as Denmark. Broadly they can be broken down into a number of different categories, which are discussed in the following sections.

The Crete system is also interesting, as it is the largest isolated or ‘island’ electricity system with wind input [27]. The major technical problems for wind farms are low frequency events, caused by insufficient generation, and poor voltage control. The major problem for the system operators is that a minimum quantity of conventional generation must be kept operating, to provide frequency control and reactive power. To keep this minimum quantity of conventional generation running at times of high wind output and low demand, the wind production is curtailed. The level of curtailment in 2001 was 6% of wind production, and this is expected to rise to approximately 20% in 2002, as more wind is connected. Fortunately the high wind season (summer) coincides with high demand, and almost all the curtailment occurs in the low-wind season. Otherwise the level of curtailment would be significantly higher. Even so, 20% curtailment clearly has a major effect on the economics of wind generation.

### 2.1.2 Ensuring generation adequacy

Power systems are designed to have sufficient production capacity (generation) to meet the variable (but predictable) load requirements of customers. Traditionally probabilistic measures have been used to assess the requirement for additional generation resource to ensure a reliable power system. One such measure in common use is Loss of Load Expectation (LOLE). This evaluates the risk of insufficient capacity in terms of the expected time per year that a peak load will exceed the available generation capacity.

Wind presents several challenges when modelled as a production resource. It is variable in amplitude, over a wide range of timescales. However its statistical properties are understood, and it is predictable to some extent on some timescales. As wind penetration grows it is imperative that appropriate modelling techniques for wind energy are utilised so that the generation adequacy of the power system as a whole does not degrade. A greater degree of wind penetration does not necessarily equate to a degradation of generation adequacy. Wind power cannot completely replace conventional power MW for MW. However getting the correct balance will require refined and constantly improved modelling of wind energy on the island, over all timeframes.

At present wind energy is taken into account when modelling generation adequacy on the ESB system [25].

### 2.1.3 The planning of the power system

Accommodating the expansion of wind power whilst ensuring the orderly and reliable development of the power system has not been faced before by most system operators and is not straightforward. Traditionally models of the power system are developed and a number of possible future scenarios (different load growth rates, new generation developments, system interconnection) are tested against a set of transmission planning criteria. Typically this analysis is carried out for 5, 7 or 10 years into the future. When the analyses indicate that the power system operation will infringe the criteria in a particular year, then system reinforcements are suggested which will bring the power system back to standard.

This orderly process of power system development, which has provided reliable electricity supply, faces a number of challenges as the penetration of wind power increases in a system. In comparison with conventional generation wind power tends to:

- Have a low capacity factor, which results in relatively high capital investment in the power system in relation to the energy production and to other benefits to the system;
- Have less predictable and controllable power production;
- Be capable of construction in much shorter timescales than is usual for transmission reinforcements, so that the transmission system may become the constraining factor on the growth of wind capacity.

In addition, wind farms constructed to date tend to:

- Locate in weak areas of the power system;
- Have less developed models of generator characteristics than conventional generation;
- Provide less support during system disturbances than conventional generation.

These are factors that challenge the system planning/modelling process. However, some of these factors can be and are being addressed by turbine manufacturers and wind farm developers, particularly for larger wind farms. Eltra, in its latest system plan, has stated its intention to modify its planning criteria/methodology to better address the unique features of wind power.

It is also interesting to note, given the Danish experience of major wind power penetration, that the strategy they are implementing is an increase in the capacity of the existing interconnection with the NORDEL system (specifically to Norway). This has the advantage of improving generation adequacy and giving a greater ability to cope with the aforementioned oversupply difficulties. This strategy may not be feasible or technically satisfactory in the case of the island of Ireland. The existing Moyle interconnection between NI and Scotland, while technically capable of 500 MW, is effectively restricted to approximately 450 MW. The available trading capacity (ATC) has been set at 300 MW to September 2002, and 400 MW to March 2003 [2]. With regard to interconnection on the island, the ATC for transfers between NI and RoI has been set at 170 MW in 2002/3 and 300 MW in 2003/4. Further expansion or new interconnections are under investigation in RoI, and would be major investments. Furthermore Scotland is seeking a significant expansion in its wind power resource, potentially eliminating some of the temporal diversity that would be exploited by increasing the capacity of the existing interconnection.

#### **2.1.4 Operation of the power system – Power and energy balance**

The day to day, moment to moment operation of the power system in developed economies with a high level of wind power penetration has proven a challenging experience. The operators must seek to balance production with generation without breaching system constraints, maintain the quality of supply to consumers, while operating the system economically. Additional variability introduced by wind, on timescales of seconds to hours, makes these tasks more difficult. From a theoretical point of view, the variability introduced by wind should not be significant until the penetration is sufficient for the variations to be similar in scale to the variability introduced by the random behaviour of electricity consumers. On short timescales of seconds or minutes, wind forecasting error over a large geographical area is expected to be small compared to load forecasts, except during extreme events such as storm fronts, on which much forecasting effort is being expended. On timescales of days, forecasts of wind production can be wrong by 100%, which is clearly much greater than the forecasting error for demand.

In Denmark where the bulk of the wind resource is of an uncontrolled nature, connected to the distribution system and is in no sense 'dispatchable' or controllable, the Danish operators have found that good wind forecasting is critical to successful operation.

As well as the problem of balancing such a system from an energy perspective, several other operational problems have emerged.

Generators deliver a range of other products that are necessary for the operation of a power system. This broad class of essential services that operators use to control the power system is named ancillary services. They range from operating reserve and reactive power through short-circuit current contribution and black start capability. The inability of wind generators to produce these ancillary services in a dispatchable, controllable way has been of serious concern to operators in Denmark. If a centrally-dispatched thermal plant, which can produce such services, is displaced by wind power in an unchecked fashion, there will be difficulties

in operating the power system. These issues are likely to emerge earlier in the RoI and NI systems, as there is much less interconnection with neighbouring systems.

### **2.1.5 Operation of the power system - Transmission**

In addition to the considerations of energy and power balance, high levels of wind penetration also have implications for the planning & operation of the transmission system. Of these, the most important is introduced by the variability of wind power output, and the need to be able to compensate for this by the provision of ancillary services (in the form of extra regulating or operating reserve) as outlined above. Conceptually it is attractive for any plant providing new ancillary services to be connected to the transmission system very close to large concentrations of wind power, and for some services there may also be technical advantages. However, in general, this is unlikely to be optimum for ancillary services such as regulating and operating reserve. In most cases existing sources of these services (pumped storage, open cycle gas turbines etc.) will be connected to the transmission system in a different part of the country, and the optimum location of new plant installed to provide these services may also be remote from the wind farms.

The output from a wind farm will vary with wind speed. If these variations are large and rapid there will be corresponding changes in the magnitudes and directions of power flows from the wind farm itself, and from the generators providing regulating and operating reserve services elsewhere on the system. Unless these are countered very quickly, the voltages on the system also will vary, and, if the variations are large enough, limits may be infringed.

Voltages on the transmission system are controlled through a combination of generator excitation systems, transformer tap-changers, static reactive devices and, increasingly, Flexible Alternating Current Transmission System devices (FACTS). FACTS devices combine modern power electronics and control techniques with elements such as capacitors, inductors and transformers. In the present context the most important FACTS device is a Static Var Compensator (SVC). Variations due to wind farms are likely to be too rapid for transformer tap-changers, and too large for the generator excitation systems of many generators. Operators may have to rely to an increasing extent on FACTS devices. These devices are well proven, but highly expensive. With greater use, their costs can be expected to reduce somewhat.

The response of the system to faults must also be considered. The issues that are particular to wind generation are:

- To provide a robust system, connections to wind farms, particularly large wind farms, could be required to provide the same level of redundancy as connections to conventional generation. This would be more expensive than connections for conventional generation, partly because wind generation is often located remote from load centres, and partly because the low capacity factor of wind generation means the energy produced per MW of new transmission capacity is low.
- It could be significantly more expensive to provide sophisticated protection systems for wind farms distributed over an area than for conventional generation of equivalent capacity.
- Conventional generation largely uses synchronous generators, which are able to continue to operate during ('ride-through') severe voltage transients produced by transmission system faults. This capacity has not yet been demonstrated for the generator/drive types currently favoured for wind generators. If large amounts of wind generation is tripped by a fault on the system, the negative effects of that fault could be greatly magnified.

- Some of the generator/drive systems currently used in wind turbines may, during a fault, consume large amounts of reactive power from the system. This may make recovery from the fault much harder.

## **2.2 New developments**

Two watershed developments in wind turbine technology are emerging:

- Construction of very large wind farms with rated outputs measured in hundreds of MW, and,
- Incorporation of increasingly sophisticated power electronic and computerised controls into wind turbines.

In addition to the above developments in wind turbine technology recent research carried out in RoI and NI and abroad may lead to significant improvements in the accuracy of wind forecasts. This is discussed in a later section.

The first of the new developments in wind turbine technology can be expected to increase the difficulties to be faced by operators; the second, combined with improvements in forecasting of wind, appears to offer a possible way to address these difficulties.

### **2.2.1 Impact of very large wind farms**

A very large wind farm with a rated output of several hundred MW, to be connected to the transmission system at a single point, will have a more significant impact on the system power and energy balance than the same total output dispersed in small wind farms over a large area. This is because, at any one time, the weather will very rarely be uniform over a large tract of country.

This means that a change in wind speed at one place would affect only that portion of the total rated output that was installed there. However, if the entire capacity were to be concentrated in that one place, the total output would be affected, and the impact on the power system would be correspondingly greater. A transmission system operator therefore could reasonably expect that the combined output of the wind farms which were widely dispersed across the country would fall to zero only in certain circumstances, so reliance could normally be placed on the availability of some proportion of their combined rated capacity. In addition, the rate of change will be lower. However, if the same total capacity were to be concentrated at one point, a much lesser reliance could be placed. Of course this dispersal of generation may require significant transmission system reinforcement

In addition, a single fault may cause the loss of significantly more wind generation if it is concentrated in fewer, larger blocks.

### **2.2.2 Impact of sophisticated controls**

The development of sophisticated controls for wind turbines, combined with possible improvements in forecasting, is expected to produce considerable improvements in the predictability and controllability of the output of large wind farms.



If this is realised, it will significantly mitigate the impact of very large wind farms, and thus improve their acceptability to TSOs. This is discussed in Section 2.4.

### 2.2.3 Wind energy power plants

The concept of Wind Energy Power Plants (WEPPs) is useful to this discussion.

In simple terms a WEPP is a wind farm that behaves exactly like a conventional generator except for the variability of the fuel source. The ideal wind energy power plant, in addition to providing energy, must:

- Deliver a range of ancillary services to the power system,
- Produce energy in a controlled fashion, ramping up and down in a manner similar to the performance of conventional generation,
- Contribute positively to system stability, fault recovery, power quality and the performance of the protection system.

TSOs in RoI and NI, Germany, GB and Denmark have all produced documents (some still in draft and confidential form) that outline the requirements for the performance of wind farms connected at the transmission voltages, and perhaps also in diluted form for smaller wind farms or even single turbines connected to distribution systems. The concept of a WEPP is part of these documents. The requirements are discussed in Section 2.4. This strategy by TSO's will be successful provided:

- it is technically possible to deliver on the requirements;
- it is possible to do so at an acceptable cost;
- there is a clear understanding of the strategy and its requirements among project developers & wind turbine manufacturers;
- the timescales for introduction of the requirements are long enough to allow the necessary design and development work to take place;
- the approaches of the TSOs are not radically different, so there is a common set of targets to meet.

This strategy would have some implications for the questions raised by CER and Ofreg on wind penetration. If entirely successful, the technical limit for overall wind penetration levels on the island will be set solely by the generation adequacy requirements of the power systems. (Naturally local transmission requirements for individual wind farms will still be a factor).

However, while this strategy is simple to implement and police from the TSO perspective, and is cost reflective, it will not be the economically most efficient for the island of Ireland. It makes little sense to compel wind farms (whose fuel source is 'free') to perform frequency regulation or provide spinning reserve when these services can be more economically provided by some of the conventional generation, even taking into account the increased operational costs for these other plants.

For clarity, it must be stated that this does not mean that TSOs are being unwise in seeking wind farms to have the capability to produce reserve (or other ancillary services). TSOs have duties to prudently cater for a range of situations (multiple forced or scheduled outages of conventional power plant providing reserve, low load periods with high wind generation, local transmission difficulties, stability considerations, etc.) where it may be necessary from a security standpoint to dispatch such a source of reserve.

Some wind project developers and manufacturers may react negatively to the requirements presently being outlined by TSOs. They may consider that these are barriers to increasing the penetration of wind power onto the system. In fact in the long term they are the opposite, as they will facilitate a greater level of wind penetration and maximise the use of the resource. However in the short to medium term there are certain dangers. This strategy will impose extra costs (capital and O&M) on project developers. There will have to be an investment of time and effort by wind turbine manufacturers and project developers in assimilating and understanding the requirements. There is a chance that some of the requirements will be unduly onerous or costly, or be too far ahead of the developing technology.

On balance the dangers outlined above are heavily outweighed by the long-term benefit of moving in this direction – maintaining system reliability and facilitating a greater penetration of wind power on the system. The dangers are real and significant in the short term, and can be mitigated. Recommendations for mitigation in an Island of Ireland context are included in Section 2.12.

## 2.3 Wind Turbine Types

For what follows, it is important to understand the important technical characteristics of the wind turbine types currently available. The dominant wind turbine configurations that are important for this study are as follows (see also the Glossary).

- Fixed-speed:
  - Pitch-regulated
  - Stall-regulated
  - Active stall
- Variable-speed:
  - Pitch-regulated

Variable-speed operation is achieved by providing a power electronic converter to connect the variable-frequency output of the generator to the fixed-frequency electricity network. This power electronic converter can also provide control of power factor.

There are several variable-speed configurations currently available, of which the most popular at this time are:

- Direct-drive
- Doubly-fed induction generator (DFIG)

## 2.4 Review of Grid Codes

Grid Codes have been agreed in many jurisdictions. Amongst other things, they set out the technical obligations of generators connected to the system. These Grid Codes have been drawn up for the dominant generator type on the system, the synchronous generator, and major parts of the requirements may be written from the viewpoint of large steam plant. Wind turbines are radically different in several areas, and so Grid Codes are going through a period of revision. There has been a wide gulf between the system operators' and planners' understanding of what wind turbines can, cannot, and may in future be able to do, and the wind farm developers' understanding of the needs of the system operators and planners. This gap is now closing.

The requirements of the Grid Codes currently available in published or draft form can be summarised as below. This summary is drawn from the latest issues of the requirements of the two Scottish TSOs, Eltra (Denmark) and E.ON Netz (Germany), and informal discussions with NGC (England and Wales). The requirements indicated here are generally the most onerous from the documents examined. Some of the requirements in the GB documents are not required at present but are to be implemented in stages up to 2007. In that case the final requirements (i.e. post 2007) are considered here.

GH has also seen an early proposal for grid code modifications by ESB National Grid.

In the following discussion, the rated output of the wind farm is designated  $P_{nom}$ .

### 2.4.1 Power cap

The TSO must be able to remotely set a limit on the output power of the wind farm. This may be required for several reasons, including:

- in case of failures or other limits within the transmission system;
- to maintain a minimum load on other generators;
- to reduce wind generation gradually in advance of a storm front (which may otherwise result in all turbines shutting down in a short period due to high windspeeds).

This limit is best implemented in the wind farm controller, i.e. not directly in the wind turbine controllers. This limits the measurement and communication requirements within the wind farm, and more importantly will take account of any wind turbines, which may be down for maintenance. The wind farm controller will implement this by sending setpoint signals to the wind turbines.

Eltra require the wind farm output (1-minute average) to be no more than  $0.05 P_{nom}$  above the power setpoint. This level of accuracy should be easily achievable with variable-speed wind turbines, and also should be achievable with pitch-regulated fixed-speed or active stall machines.

There is a further requirement for a contribution to Area Balance Control (Eltra only) which can be lumped in with this requirement. In this case the TSO will set a power setpoint which may vary on timescales of seconds, and the turbines should receive updated setpoints on timescales of approximately 1 second. Again, this is easily achievable with variable-speed wind turbines, and should be achievable with pitch-regulated fixed-speed turbines, but may be difficult for fixed-speed active stall turbines. However the frequent update rate will require improvements to currently available wind farm communications systems.

### 2.4.2 Rate of change of power: positive

The TSO should be able to limit the positive ramp rate for wind farm output power. This may be required when other plant is being required to reduce output in response to a general reduction in demand (i.e. after a daily peak). It may also be required when wind penetration becomes high enough that the wind ramp rates (in MW/s) become similar to the maximum ramp rates from conventional generation. Analysis in Section 2.7 shows this will not be an issue until very high penetrations are reached.

It is not clear whether the TSOs wish to be able to remotely adjust or activate the ramp rate control, for example when storm fronts are forecast.

The stated German limit is  $0.1 P_{\text{nom}}$  per minute. The Scottish limit is  $4 P_{\text{nom}}$  per hour, which is equivalent to  $0.07 P_{\text{nom}}$  per minute, (i.e. similar to the German limit) though clearly it is more onerous to meet a 'per minute' figure than the equivalent 'per hour' figure.

### 2.4.3 Rate of change of power: negative

Clearly it is not possible to provide a guaranteed maximum negative ramp rate from a wind farm on timescales of minutes, as a sudden reduction in wind speed is possible. However it is possible to set a ramp rate to be met during shutdowns, and this is a requirement of the Scottish code (phased reduction over 30 minutes).

Maximum negative ramp rates on timescales of hours can in principle be forecast. This could not be done with confidence at present, but what is possible now or in the near future is to forecast periods where excessive negative rates are likely to occur. In that case, the output of the wind farms can be reduced in advance, so that the maximum negative change that eventually occurs can be limited to a value that the system can cope with.

### 2.4.4 Other power control

The draft Scottish code contains two requirements not mentioned elsewhere:

- power system stabiliser function;
- control loop to limit output power fluctuations over a critical frequency band.

These requirements are to meet specific issues on the Scottish system. In principle they can be met by any pitch regulated turbine. It may be possible to demonstrate that variable-speed wind turbines cannot, for physical reasons, contribute to the low-frequency mechanical/electrical resonance that power system stabilisers seek to damp out, in which case this function would be unnecessary.

### 2.4.5 Frequency regulation

The ability to provide a conventional governor ( $df/dt$ ) droop control is required, to give a decrease in output power in the event of an increase in system frequency. Clearly, to provide an increase in output power in response to a drop in system frequency would require the turbines to be operating at below the power level possible in the wind conditions, which would waste energy. Therefore this is not required in Germany. The GB TSOs have stated that they would only require this to be implemented *in extremis*, but they require the capability to be provided when the wind farm is built.

For the purposes of debate, if it is assumed that wind farms must be operated to allow a 3% (of  $P_{\text{nom}}$ ) increase in output power to match frequency deviations, then taking capacity factor into account this equates to around 10% of annual energy production. If this is required all year round it is a major economic penalty for a technology with high capital costs and zero fuel costs. On the other hand, if it is required for only a few hours per year, for example at times of high wind output and low demand, the cost will be minimal, and probably less than the cost of constraining-off some wind farms entirely in order to keep conventional plant with frequency regulation ability on the system.

The speed of response required means that this function has to be implemented in the turbine controllers. Eltra require the response to be such that output power can be reduced from 100% to 20% in 5 seconds.

This is achievable in principal by pitch regulated turbines, although GH is not aware of any manufacturer who can offer this function at present.

#### **2.4.6 Operating voltage and frequency range**

Requirements are typically 47 to 53 Hz, with minimum time limits applying outside the range 49 to 50.3Hz (Eltra) or 49.5 to 50.5 Hz (GB).

The required voltage range is typically 90 to 110% of nominal.

These requirements should present no difficulty for wind turbines designed accordingly, though some existing fixed-speed designs may have a problem with the higher rotational speeds implied.

#### **2.4.7 Reactive power and voltage control**

Eltra require the wind farm to operate generally close to unity power factor. The Scottish TSOs require a range of 0.95 lead to 0.85 lag.

The Scottish TSOs require the wind farm to be able to operate to control local voltage, and alternatively to achieve a power factor set point. This is likely to require the TSO to instruct the wind farm on control setpoints, occasionally or frequently.

At least one wind turbine manufacturer offers this facility now, and there is no technical reason why any variable-speed machine with power electronic converter cannot also provide this. To meet the full range that may be required, increased converter capacity may be required, and one manufacturer has questioned whether it would be better to meet this wide range through power factor control equipment external to the wind turbines.

The bandwidth proposed by NGC for voltage control is fast (0.5 Hz), such that it may drive the requirements for the communications system within the wind farm.

#### **2.4.8 Transient stability ('fault ride through')**

This requirement means that the wind farm must be able to continue to operate during and after a fault on the nearby electrical system. Such a fault will produce a severe voltage dip at the wind farm. This will reduce the power that may be exported from the wind farm for a period of several hundred milliseconds, and therefore the turbines will accelerate and perhaps overspeed if nothing is done. The critical parameters are the depth and the duration of the voltage dip.

Some manufacturers of turbines equipped with doubly-fed induction generators are known to be able to meet this requirement, or to expect to meet it shortly, for voltage dips down to 15% retained and durations of 300 ms.

The Scottish draft code seems to be the most onerous, requiring (by 2004) the ability to survive dips to zero voltage for 140 ms. The situation is not clear, but at least one manufacturer anticipates achieving this, although with a period of a few seconds post-fault before full power can be restored. GH cannot see a reason why this requirement cannot be achieved by variable speed pitch-regulated machines in future. There may be a delay of up to a second or two before the output can be ramped up to full power again, but this does not seem to be an issue for the TSOs at present.

## **2.4.9 Summary of review of grid codes**

### ***General summary***

The general conclusions are as follows:

- Most of the likely requirements are expected to be provided, if required, by wind turbine manufacturers by 2005, at negligible cost.
- Transient stability is the most onerous requirement to meet.
- Some wind turbine types will have competitive advantages.
- For requirements which can only be met by wind turbines by reducing output, and therefore losing energy (such as frequency response and reserve capacity), it would be economically most efficient for these requirements to be met by conventional generation, possibly through some kind of market mechanism.
- Detailed dynamic models of wind turbines will be required in order that TSOs can carry out their studies. Developing and validating these models may be difficult.
- It is possible that type-testing of wind turbines will be required in order to demonstrate compliance with the requirements
- There will be significant advantages if TSOs can agree similar, not necessarily identical, sets of requirements. In particular it is important that different type tests of wind turbines are not required for different TSOs.

### ***Detailed points***

Most of the requirements can be met with minor improvements to wind turbine and wind farm controller software and possibly hardware. Most of this cost is development effort and is therefore negligible in the context of series production.

The hardware affected is principally the communications system within the wind farm and externally, and the blade pitch systems.

The time to develop these functions may well be less than the time necessary for discussion and agreement of Grid Code modifications.

The most onerous requirement is for transient stability, and this will require development effort by turbine manufacturers. The depth and duration of the voltage dip are critically important, and TSOs should set these requirements carefully.

Fixed-speed wind turbines, in particular stall-regulated and active-stall concepts, are at a technical disadvantage, but it appears likely that these could still meet the requirements with the addition of other equipment within the wind farm, thereby turning this technical disadvantage into a cost disadvantage. Therefore it is best for TSOs to specify technical requirements, rather than to specify technologies.

GH considers that this cost disadvantage will be severe for stall-regulated turbines, but has not quantified this.

It may not be justified to require all the above functions from the smallest wind farms or single turbines, particularly those requirements which are proportionately expensive for small projects, and where the need is a system-wide rather than a local issue (e.g. frequency control and ramp rates). This approach is being followed in GB. It may be that TSOs can accept small installations, below some '*de minimis*' limit, which are not fully compliant, up until the total capacity of such non-compliant installations exceeds some limit. Existing wind farms would fall in this category.

For the functions, which require loss of production, it is economically beneficial to implement those functions on other generation, with wind possibly as a 'last resort'.

The GB TSOs are requiring that the commands of the TSO are passed to a manned control room, which is not necessarily on site, but which has secure communication channels with the wind farm. Smaller projects do not need direct remote control. However in Denmark it appears that Eltra are envisaging direct control by the TSO. GH sees no reason why wind farm operators should object to direct control by the TSO, provided the conditions under which it is implemented are fully understood and agreed, and provided the exercise of that control is fully recorded and impartial. Direct control by the TSO is probably cheaper for the wind farm operator, and allows the TSO to have direct confirmation that their instruction is complied with.

Many of the above functions cannot readily be tested on site, as the TSOs would tend to do for conventional generators. This is partly due to the effect of specific wind conditions, and partly because a wind farm may be made up of many turbines, each of which could require testing. It is likely that type testing of turbines by third parties will be adopted for some of these functions. If this is not required by the TSOs, it is likely to be required by project funders, to remove the risk of non-compliance.

As is done for conventional generation, the owner is required to deliver models of the turbines and controllers that will allow the TSO to simulate the system. In particular, after a fault, the TSO can compare the simulated behaviour with the actual behaviour, and if the wind farm has failed to perform as specified, penalties may be payable and the wind farm could be disconnected pending demonstrated remedy. For this purpose, the Danish and Scottish operators will install fault-recording equipment.

The development of suitable models is currently an area of difficulty, particularly for the doubly fed induction generator. Depending on the wind turbine type, it may be necessary to include wind turbine drive train dynamics in the simulations.

It is GH's experience that wind turbine control parameters actually installed may differ from the control parameters originally intended. This may be less of an issue for large wind farms with professional O&M organisations. Nevertheless GH considers that TSO requirements for fault recording equipment are justified, as are penalties for failing to perform as stated.

## **2.5 Frequency Reserve**

This issue is not dealt with in Grid Code modification proposals. It is discussed in Section 6.2.

## 2.6 Wind Forecasting

Clearly wind forecasting is an important issue for transmission system operation and planning. The current ability and prospects for forecasting are reviewed here.

This issue is closely related to the issue of wind variability, which is discussed in a subsequent section.

### 2.6.1 Forecasting techniques

State-of-the-art forecasting of wind energy uses a modeling chain to predict wind energy for look-ahead periods of, typically, up to 48 hours. Up to 2 or 3 hours ahead, simple persistence forecasting (i.e. what happens now will also happen N hours from now) performs relatively well, though it is possible to improve upon this by using statistical regression of recent wind farm output. Beyond 2 to 3 hours, forecasting can improve significantly on persistence (e.g. 30 to 60 % improvements in RMSE (Root Mean Square Error), depending on time horizon) by using forecast data from the relevant national meteorological offices' Numerical Weather Prediction (NWP) models. Typically, such NWP output is fed into a separate model, which is used to create site-specific wind speed and wind power estimates.

In recent years, much research has concentrated on this area of transforming low-resolution NWP forecasts into more accurate site-specific ones. The interest in this field is increasing, as the technical implications of increasing wind penetration on electricity networks is being realised. It should not be forgotten, of course, that there are other relevant factors driving this process, such as participation in energy trading markets and the improved scheduling of wind farm maintenance.

The national meteorological institutes aim to identify, replicate and predict the general synoptic characteristics of the weather over large areas. To achieve this, they run mathematically complex and computer intensive models. These models cover extensive geographic areas – sometimes the whole world. The institutes also have large data feedback infrastructures in place, which enable constant fine-tuning of their models. The problem is, of course, that such large models can only operate at relatively coarse resolution. The Met Office in the UK, for instance, runs a global model at 60 km horizontal resolution, which is refined to 20 km for most of Europe and to 12 km for the UK and northwestern Europe. Even the highest resolution (12 km) will not be able to replicate accurately what happens at specific sites.

The methods of achieving the transformation between coarse NWP forecasts and site-specific ones are varied. There are many methods in use, both as academic research and as commercially viable products. Despite this variation, they can largely be grouped into 2 main types:

- Statistical models.
- Physical models.

The statistical model approach is basically a multi-input regression analysis on a combination of meteorological parameters. The philosophy is that the majority of differences between NWP output and a site are systematic and as such can be identified and removed. Non-linear regression techniques can be used, typically through fuzzy-logic algorithms or through the use of neural network software.



The physical model approach primarily aims to improve the resolution of the “original” NWP model. Again, the methods are varied and can include:

- Simple linear-flow models, such as WAsP or WindMap.
- Fine resolution NWP models, such as MM5. These are essentially local (nested) versions of the original NWP model and are often termed storm-scale or convective-scale. They aim to model local thermal effects that are not apparent at the coarse scale.
- CFD (Computational Fluid Dynamics) models.

Such physical models typically aim to increase the resolution from 10 or 20 km, to 1 or 2 km, though examples of finer resolution (up to 20 m) have been noted.

At present, neither approach (statistical or physical) can be termed “best”. Both have their benefits and drawbacks. The statistical approach is relatively simple and very adaptable between geographic areas. In many situations it performs well. However, in very complex terrain, or when there is very strong thermal forcing at local scales, the physical models can prove better. There are some added complications of physical models, though:

- Skill – The implementation of NWP models requires the skill and competency of a meteorologist. There is always the possibility of a poorly formed model introducing further errors.
- Computational requirements – The formulation and execution of the models is very computationally expensive.

The physical models often incorporate a post-processing statistical model, which again is there to remove any remaining systematic errors.

It is worth noting that all approaches benefit significantly from on-line feedback from the site. This allows any statistical correction to be adaptive and avoids the need for periodic retraining of the models.

The aim of the above approaches is to produce site-specific forecasts. A system operator needs to know what is happening at all the wind farms on the network. In situations where it is not practical to forecast for each individual wind farm, the practice of “up-scaling” can be employed. In this scenario, a selection of representative wind farms are modelled and forecast for, with the results being up-scaled to reflect the total capacity of wind energy on the system. Modelling a few wind farms is clearly cheaper than modelling them all and, if the chosen wind farms are truly representative of the others, such an approach should introduce very little error.

The use of wind forecasting systems is increasing. GH’s knowledge of network operators currently utilising wind forecasting systems includes:

- Red Electra, Spain
- E.ON, Germany
- Eltra, Denmark.

However, it is worth noting that the nature of electricity markets, and their regulation, differs significantly between countries. In some cases, the onus for forecasting falls on wind farm operators, rather than network operators. Many American states are an example of this. In other words, if the above list was expanded to include networks where forecasting is being used at some level (i.e. not just at the network operator level), then it would be considerably

longer. Similarly, if it were to include networks which are *investigating* the use of forecasting (such as ESB National Grid), then again the list would be greater.

### 2.6.2 Forecast uncertainties

It is important to appreciate that no forecasting method will produce exact forecasts. There are always uncertainties regarding forecasts and it is being increasingly realised that proper use and knowledge of the uncertainties is at least as important as better forecasting techniques, if not more so. Uncertainties can be established on a post-processing basis, with statistics built up over time. This information can then be used to inform decisions based on future forecasts. However, it is better still if a forecast can come complete with an uncertainty – this enables very specific, up to date knowledge regarding both the current synoptic and model states to be accounted for. Such information is typically established by the use of ensemble forecasting, which investigates the impact of changes to the initial conditions of the model.

Again, much research is being done in this field. In an Irish context, it is worth noting the work currently being explored by University College Cork and ESB. The approach here consists of a number of different deterministic numerical weather prediction models. The output of these are fed into a statistical analysis tool, which selects the most likely forecast and derives a probability distribution of the model output parameters such as wind speed and wind power. This multi-model approach has been tested over a 3-month period for Denmark. The improvements compared to a single deterministic forecast are significant. It has also been found that an uncertainty estimate derived from the probability distribution of a certain weather development is highly correlated with the forecast error. In other words, the user of the forecast is alerted to periods when the forecast is less, or more, certain. This is important information, which the transmission system operator requires in order to successfully carry out the planning and scheduling functions.

### 2.6.3 Forecasting requirements

The requirements of system operators in the RoI and NI context can be summarised as follows.

Forecasting error must be ‘acceptable’ up to approximately 12 hours ahead. The longest start-up time (cold to full power) for existing generation on the island is approximately 8 to 10 hours (steam plant with drum boilers, e.g. Moneypoint in the Republic and all steam generation in Northern Ireland). Other large steam plant with once-through boilers can go from cold to full load in three to four hours. Therefore forecasts further ahead that are found to be wrong at 12 hours ahead can be dealt with, at a cost in additional start-ups.

Forecasts further ahead than 12 hours would be useful for maintenance planning.

‘Acceptable’ means that the forecasting errors are small enough that system operators can cope with the actual out-turn, at acceptable cost. Clearly large forecasting errors would be ‘acceptable’ if the system had large quantities of rapid-start plant such as open-cycle gas turbines and pump-storage schemes, but this implies considerable cost. In this case, ‘acceptable’ means within the capabilities of the existing generation.

The forecasts should include an estimate of the forecasting error. The forecasting error is dependent on the meteorological circumstances. For system operation purposes, what is

required is an estimate of the worst-case or maximum error (in each direction), not the mean error. For periods with a high forecast error, system operators could, if necessary, curtail wind generation, or impose tighter limits on rate of change of power. High forecast error is associated with passage of storm fronts, when there will be rapid changes in output from wind farms. The worst case is when the wind speed increases above the cut-out speed of the wind turbines, causing all to shut down within a short period. Means by which this can be ameliorated are discussed in Section 2.4.

The most critical periods for demand forecasting are the overnight trough, the morning rise, and the peaks.

ESB system operators also stated that they need regional forecasts, e.g. for Donegal. As all methods can give forecasts for particular points, this is achievable, but it may be important to achieve acceptable forecasting errors for regions as well as for the whole system.

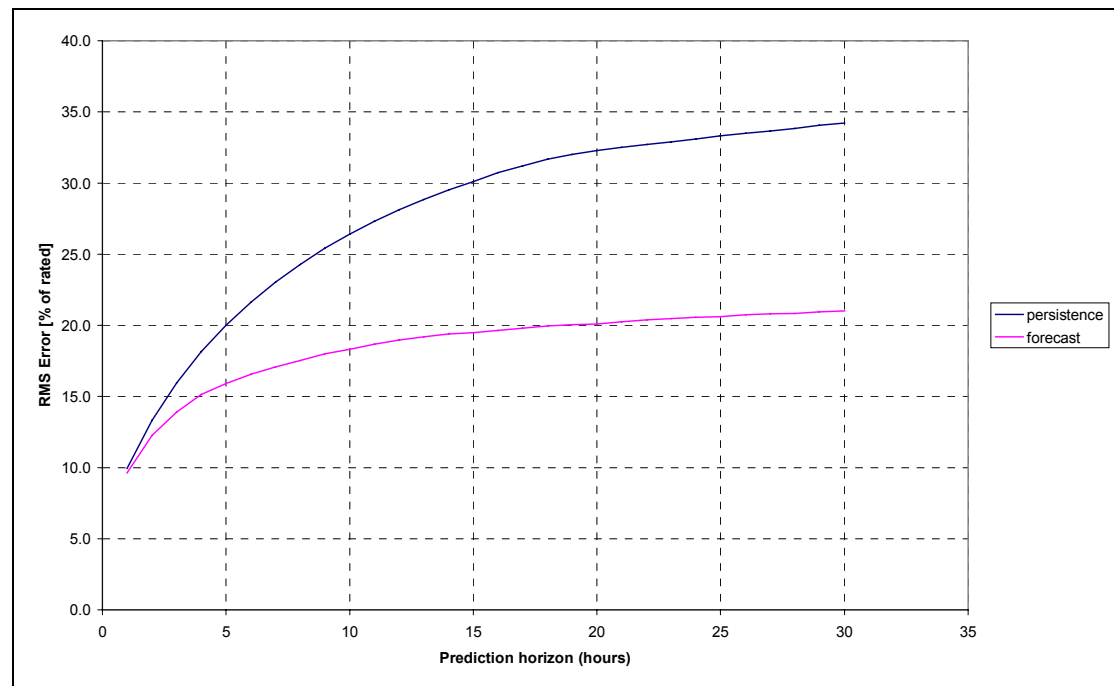
#### **2.6.4 Forecasting capabilities**

Real-time wind energy forecasting uses forecasts up to 48 hours ahead. As previously mentioned, no model system at present is capable of fulfilling the 'ideal' accuracy requirements of a system operator.

Output from the NWP models at longer timescales can be made available but is not currently used for wind power forecasting. In any event, the forecasting errors increase with lookahead time, and at some point it becomes better to use long-term mean values. For instance, the long-term mean wind speed for the required hour of the day and the required week or month could be used. The point at which long-term mean values are better than forecasts is not known, but may be of the order of a few days. This is the timescale for maintenance planning.

Figure 2.1 shows the rms error (in % of rated power) for one wind farm, produced by comparing forecasts against actual output for one year. It is seen that the 'persistence method' (i.e. assuming that the current value persists) is as good as the NWP forecasts up to one hour ahead. Beyond that the NWP forecasts are significantly better, giving rms forecast errors of 15% of rated power at 4 hours ahead, and 21% at 24 hours ahead. Note that the forecast technique used in this figure is not necessarily optimal, and would be expected to give lower errors at low wind speeds (around wind turbine cut-in) and high wind speeds (cut-out).

This figure is provided for illustration only. As noted above, the system operators should be more concerned with worst-case rather than mean errors.



**Figure 2.1: RMS Error of prediction of wind farm output power, for persistence method and forecast. Sample wind farm, 2000**

## 2.6.5 Implications for the RoI and NI systems

For most of the time, the forecast errors expected at timescales out to 12 hours should not cause the combined RoI and NI system insurmountable difficulties, with the existing plant mix.

The critical issue is the worst-case forecast error that has to be planned for. In fact, the worst-case underestimate of wind power is not of particular concern, if the system operator can remotely limit output power and positive ramp rate from sufficient wind farms. This is realistic and is discussed in Section 2.4.

However, the measures required to cope with errors in wind forecasting:

- additional start-ups of conventional plant;
- rapid ramps in output power from conventional plant;
- ensuring that conventional plant is loaded below its economic optimum in order to be able to be ramped up if necessary;
- and curtailing wind generation;

all add to operating costs. Therefore it can be concluded that improvements in wind forecasting are not necessary in order to increase the penetration of wind on the system, but are justified on economic grounds: they will reduce the system costs attributable to wind generation.

## 2.7 Wind Variability

Wind is often characterised as ‘unpredictable’. This is often confused with variability. As is shown above, the output of wind farms is forecastable within an error band. However, even if wind was perfectly forecastable, the issue of its variability would still be important for system operators. This section reviews the issue of variability. A summary is given at the end of the section.

This issue has been examined by several authors in the past [19]. Typical results are shown in [20], based on four widely separated met. stations in the UK, using hourly wind speed data from three representative years. The variability of the summated output of fictitious wind farms at these locations is reduced compared to the variability of any one site alone.

Similar analysis was carried out for RoI by Ecofys [21]. This used a more extensive dataset (five met. stations and ten years of hourly data).

Analysis of approximately 1500 operating wind turbines in Germany [22],[23] shows variations in summated wind power output as a function of frequency of occurrence. The results show, for periods of one hour, variations of approximately +/- 20% occurring with a probability of 0.01%.

One year of data at 1-second resolution from two operating wind farms (103.5 and 113.25 MW) in Minnesota and Iowa is reported in [33]. For the combined data, maximum rates of change of 4.3 % of rated power per minute and 32% per hour are reported.

However, apart from [33] and the ISET results [23] (believed to be at 15-minute resolution), there was little published analysis of data at sub-hourly timescales, particularly using wind power data (i.e. output of operating wind farms) rather than met. data, and none for Irish or UK conditions. As part of this study, GH therefore undertook analysis of wind farm output data from four wind farms operated by ScottishPower. The data spanned approximately a year at each site and were at ten-minute resolution. This analysis is reported in detail in Appendix 4.

The data were from operating wind farms and it was not possible to identify occasions where rapid changes in output power were due to disturbances on the distribution system resulting in the entire wind farm shutting down. This could be the cause of some of the most extreme events. This cause is not strictly relevant for this analysis, but could not be identified and excluded.

The data used were from operating wind farms without any attempt to control the power fluctuations. The fluctuations could be controlled in a number of ways:

- Staggered starting, to prevent several turbines starting in a short time. This is achievable by the wind farm SCADA system at no significant cost.
- Staggered shutdown, to prevent several turbines shutting down in high winds in a short time. This is more complex, as it entails either some loss of production or some increased fatigue damage to the turbines, but again is achievable at no significant cost.
- Control of positive ramp rate. Pitch-controlled wind turbines can have the rate of increase of output power limited by the pitch system, either by the wind turbine controller or by the wind farm controller. This entails no significant capital cost. There will be some loss of production, but for the ramp rates currently proposed by system operators it is not thought to be significant.

- Control of negative ramp rate. This requires forecasting, and is discussed in more detail in Section 2.4.

From the above it is concluded that the most extreme fluctuations over short timescales (10 to 30 minutes) that were encountered in this analysis could be reduced in magnitude and frequency, but it is not clear by how much.

It was shown that, when the resolution of the input data was decreased from 10 minutes to 1 hour, the results for multiple wind farms agree with previous work by Ecofys. Indeed, this work may suggest that the reality is slightly better than predicted by Ecofys (which based analysis on recorded wind speeds rather than recorded wind farm outputs). However, such a conclusion cannot easily be drawn as there are several other factors, which may have influenced this trend. Until further data are available from operating wind farms for concurrent periods of several years, the trends shown in Appendix 4 may be used.

As expected, both the ScottishPower data and the Ecofys study show significant reduction in variations in summated output power when wind farms were dispersed, compared to single wind farms.

It is also concluded that, when system planners and operators are interested in the variation in net power output of multiple wind farms over short periods (up to approximately one hour), it is important to use data with averaging or sample periods substantially less than one hour, e.g. ten minutes. Using hourly-averaged data will produce misleading (optimistic) results.

Appendix 4 also presents a method for estimating the worst-case power fluctuation to be taken into account by system planners. Depending on the probability of occurrence acceptable to the system planners, it appears that over periods of several hours, worst-case power fluctuations of 100% of total installed wind capacity should be expected. Analysis of the ISET operating data from 1500 wind turbines in Germany in 1998 [23] shows a much lower figure, approximately 50% over four hours, and 20% over one hour. The US data showed 32% in one hour, as noted above. The reasons for differences between these results and the Ecofys and ScottishPower results are not understood, but may be due to different wind conditions in Germany and the greater geographic extent of the input data. Therefore for the purposes of this study a worst-case change of 100% over periods of four hours or more is assumed. This assumes no mitigation achieved by changes in operational practices, and is therefore a conservative assumption.

When comparing this conclusion with other published work (e.g. [22]) it is important to distinguish between the maximum power variation observed in recorded data of limited duration, and the maximum power variation which can credibly be expected over the long term, to some agreed level of confidence. The latter is larger.

The situation for shorter periods ahead (up to say one hour) is not so clear due to the lack of suitable long-term concurrent data at high resolution (e.g. ten minutes) from multiple wind farms. However, as an example, if the acceptable probability of occurrence of an event is taken as once in 100 years, the results of Appendix 4 (which are based on 10-minute average data) indicate that the worst-case power change over one hour which system operators and planners have to deal with is approximately 90% of installed wind generation capacity. This figure is based on only two wind farms, and so concurrent data from more wind farms would be likely to reduce this figure to some extent. The equivalent figure from the ISET analysis [23] is estimated by extrapolation to be 30%. As noted above, there may be reasons why the ISET data is not applicable in RoI and NI, and so for the purposes of this study a worst-case fluctuation of 90% over one hour is assumed. Again, this is a conservative assumption.

Such extreme power fluctuations are likely to be foreseen by wind forecasts, and also could be mitigated by the wind farm control measures discussed above.

To quantify this effect, the worst-case fluctuation defined above (90% of installed wind capacity over 1 hour) can be compared to the ramp rate required from conventional generation in the RoI Grid Code, which is 1.5% of Registered Capacity per minute, or 90% per hour. From this it is concluded that the conventional generation is likely to be able to cope with the worst-case ramp rates from wind generation over timescales of up to one hour, until very high wind penetration levels are reached.

Instead, the limiting factor is the speed at which further conventional generation can be started up, when the output of the wind generation reduces and the output of the conventional generation connected at the time has been ramped up to its maximum level. This is therefore a forecasting issue.

### ***Summary***

For the purposes of this study it is assumed, based on the analysis above, that the worst-case power fluctuation over periods of several hours, from multiple wind farms, which must be taken into account by system operators is 100%. For periods of one hour, a figure of 90% is suggested, but this depends on an assumed acceptable frequency of occurrence, and should be reviewed by the TSOs. This is in any case a conservative estimate, and further data from multiple wind farms may allow this figure to be reduced further.

These high rates-of-change may cause difficulties for system operators, depending on the confidence with which they can be forecast.

The most severe fluctuations in output from wind farms over timescales of minutes can be controlled by various means, which may be beneficial to system operators. This is not currently done.

## **2.8 Incidence of Calms, and Capacity Credit**

The wind industry commonly claims that the variability of wind farm output should not be a significant problem for system operators and planners, due to the “averaging” effect of geographical dispersion. This is clearly true for very short-term variations, which affect power quality (voltage flicker and voltage steps). In addition, the operating data reviewed in the above section shows that variability of wind farm output on longer timescales (minutes upwards) is significantly reduced by geographical dispersion.

However, there is a related issue which system operators bring up in such discussions: the likelihood of zero or near-zero output from all wind farms in an area. This issue is related to the ‘capacity credit’ that can be credited to wind generation, i.e. how ‘firm’ it can be considered, from a system planner’s point of view. The likelihood of there being insufficient generation to meet demand throughout the year is quantified in the ‘Loss of Load Expectation’ (LOLE). A good explanation of this quantity is given in [25].

No generation plant is 100% reliable, but the complete system operates satisfactorily because the probability of several generators failing at the same time is very small. However, ‘failure’ of all wind generation in an area due to low wind is considered credible. ESB National Grid have recorded instances where all wind farms on the system were producing very little output.

This issue may be more important for RoI and NI because of the very limited interconnection to other systems.

Wind generation is currently taken into account in planning the RoI system [25] [34]. A year of data from operating wind farms is combined with wind speed data from a proposed offshore wind farm location. This is used to modify the demand data used in the generation adequacy calculation, and the decrease in the requirement for conventional plant is attributed to wind.

The result is that for wind energy capacity up to at least 800 MW, the capacity credit of wind is about 20%, i.e. 100 MW of wind provides approximately the same contribution to LOLE as 20 MW of conventional generation.

To illuminate this issue, some analysis is reported in Appendices 4 and 5. The scope of this study does not include a full LOLE analysis, which is the role of the TSOs. Instead, Appendix 5 analyses wind speed data from five Met Éireann met stations spread across the Republic. (Concurrent data for Northern Ireland could not be obtained from the UK Met. Office at a suitable cost.) It is concluded that there are significant numbers of events where all wind farms on the island can be expected to be operating at less than 10% of rated power (223 hours per year, or 2.5% of the year).

These events are concentrated in the summer, but there are still a significant number of events in the winter. The contribution to LOLE on the RoI system is understood to be relatively uniformly spread across the year, because of planned outages in the summer months. However the winter months are expected to be more critical, as planned maintenance in the summer can, to some extent, take into account wind production forecasts. It was found that on average in any winter there will be 5.5 hours of very low wind farm output during the critical late afternoon/early evening periods.

It is concluded that on the island of Ireland, periods of low wind farm output are often correlated across the whole island, including the winter quarter, and so wind farms cannot be considered to be completely independent from a system planner's view.

It must be noted that this conclusion appears to disagree with some other more detailed studies (see [22] for a brief review). An early paper on the ESB system [24] determined a capacity credit of 35% of wind capacity for the first few megawatts (i.e. approximating to the annual capacity factor), falling to 14% for 2000 MW and 11% for 3000 MW. This study used five years of wind data, which should be sufficient to capture inter-annual variations. These results agree approximately with the ESB National Grid Generation Adequacy Report [34].

It is recommended that a detailed study of capacity credit for wind and its contribution to LOLE should be undertaken with high quality concurrent data from as many well distributed wind farm sites as possible. Ideally these should be operating wind farms, but wind speed data recorded at potential wind farm sites (not met. stations) could also be used to increase the geographical coverage.

This is best carried out by both TSOs, as part of their regular reviews of generation adequacy. Ideally the studies by both TSOs should be co-ordinated. The methodology used by ESB National Grid in [34] appears sound, except in the reliance on one year's data. GH recommends using as many other years of data as are available, and performing sensitivity studies by time shifting the wind data by several hours relative to demand data.



The benefits of being able to determine the effect of wind on LOLE are twofold:

- Determining a capacity credit for wind generation will allow greater economic efficiency in the development of both systems.
- There is an opportunity to recompense wind generators more accurately for their benefits to the system.

For the second point, wind generators should be aware that the value of the capacity credit attributable to any wind farm will decrease as wind penetration increases.

Of course, if there is a competitive market for generation (whether for all generators, or for restricted groups as in AER or NI-NFFO arrangements), payments to generators for capacity credit and other non-energy factors are likely to result simply in the generator's income from energy payments being reduced accordingly by commercial pressures. In this respect, capacity credit payments are likely, if correctly calculated, to favour renewable generators such as biomass, at the expense of wind.

Appendix 5 also contains an analysis of the output of wind farms in Scotland and Wales during the calm periods identified in the Met Éireann data. The results appear to be conclusive: for 94% of the periods when wind farms on the island of Ireland were producing less than 10% of rated power, the wind farms on the island of Britain were also producing less than 10% of rated power. This result is based on only one year of data, in which there occurred very few calm periods in winter, and data for further years would be beneficial. However, until further data is available, it is concluded that interconnectors with Scotland and Wales have little value in improving the 'firmness' of wind generation on the island of Ireland.

Clearly by looking further afield it will be possible to find areas of wind generation where output is largely uncorrelated with RoI and NI wind farms. Cornwall and Devon are probably too close, whereas eastern England (onshore and offshore) and northern Scotland may be more promising. However interconnection with these regions for the purposes of transferring wind energy appears unlikely to be economically feasible at present.

## **2.9 Views of Interested Parties**

### **2.9.1 Discussions with Regulators**

The Electricity Regulation Act 1999 (*'the Act'*) established the Commission for Energy Regulation. Section (9)(4)(f) places a duty on the Commission to have regard to the need to promote the use of renewable, sustainable or alternative forms of energy in carrying out its duty to protect the interests of final customers, while (9)(4)(e) requires the Commission in carrying out this duty to customers to promote the continuity, security and quality of supplies of electricity.

Ofreg's obligations for renewable sources are less well defined than those of CER. The NI Electricity Order only states that the Regulator must have regard to the environment in carrying out duties. Ofreg presently promotes renewables as a means of increasing competition in generation and supply.

From early discussions with CER and Ofreg, the project team decided to base the study on three target years, 2005, 2007 and 2010. The decision was made taking into account the timescales for political targets for renewables (2005 and 2010), and the regulatory review timetable (2007) for the system operators and planners.

## 2.9.2 Discussions with system operators and planners

Meetings have been held with staff from ESB National Grid, SONI (System Operator for Northern Ireland)/NIE, and Scottish Power (SP Power Systems).

Both SONI/NIE and ESB National Grid have provided models of the development of the power systems in NI and RoI as envisaged for the study years 2005, 2007 and 2010. They formed the basic input data for the analysis of Tasks 4 and 5.

There is no guarantee that the power systems will actually develop in accordance with these projections. For instance, the models provided by ESB National Grid are not of the envisaged network development. It is important to put these models in the correct context. ESB National Grid were requested to provide network models that meet the applicable planning standards. The models provided include developments that were selected and approved within ESB, following detailed examination. These are listed in the ESB NG forecast statement, 2001/2 to 2007/8 Supplement. With these developments alone the network is unlikely to meet planning standards in all parts of the country. Therefore the models also include theoretical developments in areas where problems have been identified. It is important to note that these theoretical developments have not been through a rigorous examination by ESB NG. Their inclusion here does not indicate that they will be required, nor indeed that they are achievable by a specified year.

NIE/DETI carried out a separate study specifically for the NIE system [3], which has taken place largely in parallel with this study. A comparison of the results of the two studies was to have been included in Appendix 2, but is omitted as the final report of this study has not yet been published.

Both organisations have a wide range of concerns. They can be split into three main areas:

### ***Simulation of wind farms***

There is substantial work in progress to determine how best to model the wind turbines. System operators and planners expect to use simulations to determine the effect of new generation on their system, but at present there are two problems:

- the power-systems simulation packages do not have suitable models for wind turbines (particularly the wound-rotor induction generators which are not known from other industries);
- the turbine manufacturers are not able to supply suitable parameters.

There are related questions about the necessary degree of modelling of mechanical and aerodynamic effects. These issues are not specific to RoI and NI and it appears rapid progress is being made, so they will not be studied in detail in this project. The results of work in progress, at UMIST in particular, are reviewed in Sections 2.4 and 6.

### ***Reliability, variability and forecasting***

There is concern about the variability of wind on timescales from seconds to weeks.

Variability on timescales of seconds is a power quality issue and is addressed in Section 4. Timescales of minutes to hours raise issues of reserve and unit commitment, and appear to

cause the greatest concern. Variations on timescales of approximately 12 hours or more relate to scheduling of conventional plant, especially for maintenance, and for scheduling of hydro. These issues are reviewed in Sections 2.6, 2.7 and 6.

It is recognised that forecasting can assist, but there is concern amongst TSOs that too much hope is being invested by the wind industry in possible future improvements in forecasting. Much of the published work on forecasting is based on hourly data, which is too coarse a resolution to see some of the issues of concern. Reliance on forecasts must be limited until sufficient track record has been established. Even with perfect forecasting, the high ramp rates expected may cause problems. This is reviewed in Section 2.7.

Forecasting techniques are expected to improve but rapid improvements (i.e. within a year) in accuracy of forecasts are not expected.

It is accepted that geographical dispersion will smooth out variations, but the operators point to recorded data, from the Eltra system and from RoI and NI, for periods of days in winter (the time of highest system demand and therefore important in generation adequacy terms) which show very low winds over wide areas. This issue is reviewed in Section 2.8.

### ***Loss of ancillary services***

If conventional generation is displaced from the system, services, which are currently provided to the system (frequency control, fault current, reserve, reactive power and others), will not be available. As noted earlier, one option is to demand that all wind farms behave like conventional generators, but this may not be economically optimum. Some services may best be provided by conventional generators, who could be rewarded directly, or markets could be set up (for reserve, for example). Wind generation could choose to buy or sell services to those markets. Almost certainly different solutions will be suitable for different ancillary services.

## **2.9.3 Discussions with the wind industry**

The principal means of consultation with the wind industry for this project is by comment on the deliverables such as the first interim report [1].

Discussions have also been held with representatives of IWEA. There is a particular concern about the uncertainties currently surrounding network connections for large offshore wind farms in RoI, particularly the timescales, support mechanisms, and the regulatory process. They were aware of the proposals for grid code changes, and considered that:

- some of the draft requirements, such as transient stability ('fault ride-through'), would be difficult and expensive to meet;
- some should be relatively simple and cheap to meet, given adequate time and clarity for turbine manufacturers to develop solutions.

IWEA considered that wind developers would be willing to accept contractual arrangements under which wind farms could be 'constrained', i.e. output limited by the system operator, under specific operating conditions. These operating conditions would be expected to occur infrequently (for example, high wind farm output coinciding with low-demand periods on summer nights). IWEA consider this principle could significantly reduce connection and network reinforcement costs, with an insignificant effect on annual production.

IWEA also considered that the potential benefits of further interconnection with the GB system are important.

Of the current proposals for revisions to the Grid Code, IWEA identified fault ride-through as a significant issue, and stated that wind turbine manufacturers were understood to be working on technical solutions.

## **2.10 Characteristics of Project Developers in RoI and NI**

There is significant diversity in the background of wind project developers active in the RoI and NI markets. There are three broad classes:

- individuals (usually with a farming background) who wish to locate a single turbine on their land;
- developers from a variety of backgrounds interested in projects of several turbines, in the range 5 to 50 MW, and probably seeking connection to the distribution system;
- large organisations aiming to develop large offshore wind farms (and large onshore wind farms, if possible) for connection to the transmission system, as well as smaller onshore wind farms.

The smaller organisations have fewer resources, less technical understanding of the issues surrounding network connection and operation, and less ability to keep up with and contribute to regulatory and commercial developments.

This diversity presents a significant challenge to Regulators and TSOs. The needs of these distinct groups have to be addressed when interfacing with the ‘industry’ and the disparity in resource and technical knowledge allowed for.

## **2.11 Administration and Business Process Issues**

During consultation with project developers in the RoI the perceived difficulty of getting a connection to the transmission system was raised. It is clear that some groups have found the connection process at the transmission level to be slow. When questioned more closely as to why this perception exists the following suggestions were given:

- Administrative procedures unsuited to the new demands placed on them
- Overly legalistic interpretation of the connection process
- Lack of resources in the TSO devoted to processing customer connections
- Requirements written for conventional generation.

It must be noted that these comments are based on past experience, with a set of procedures not designed to cope with the type and volume of enquiries which have been experienced, and some developers may not yet be aware of recent improvements in the process.

Wind farm developers world-wide generally hold similar views of the connection process, at both distribution and transmission levels. It should be noted that system operators and planners can also list some difficulties in dealing with wind farm developers:

- Project developers can have unrealistic expectations of the timescales for network reinforcements
- Project developers are concerned with a particular project, and do not see the ‘big picture’, i.e. the system operator’s general responsibility to all users of the system
- The level of technical information provided, and the confidence that can be placed in it, can be lower than for conventional generation.

If the ambitious targets for wind power set by the policy makers on the island are to be met, it is clear that the connection process must not be seen as a barrier. CER has already consulted on and approved a document published by ESB [4], which is a guide to connection to the ESB distribution system. Comments on possible improvements to this document would be welcomed by CER. An equivalent document for the transmission system is in draft form.

ESB National Grid has recently announced a reduction in the time to process applications, which is a positive step.

In Northern Ireland, as a result of the Trading and Renewables Implementation Group (TRIG), issues regarding the transparency and complexity of connection arrangements and charges have been recognised. Ofreg plan to work with NIE on further means of clarifying the connection process especially for small wind producers. These developments are likely to remove some of the difficulties facing wind developers, and may reduce the demands on the TSOs.

Based on the above, some recommendations can be proposed. These are given in the spirit of facilitating a greater penetration of wind power on the electricity system on the island of Ireland, on the timescales envisaged by legislative targets, without negatively impacting present levels of reliability. They are not ranked in any particular order of importance.

1. It is clear to all parties involved in the industry that **modifications to the grid codes** to accommodate the development of larger scale wind farms are required. ESB National Grid in the RoI has started this process internally. This would eventually lead to modifications to the Grid Code through the Grid Code Review Panel. This is likely to be a contentious process with complex issues to be resolved. In an effort to bridge the gap between the requirements of the system operators and planners, and the technical solutions potentially available to wind turbine manufacturers and project developers, the Regulators should organise (or sponsor) **industry seminars** in both jurisdictions.
2. In advance of the completion of 1 above, the Regulators should develop procedures by which **Grid Code derogations** for wind projects are processed. Because of the present necessity for all wind projects connected to the transmission system in RoI to secure a derogation, the process is seen as slow by developers. It is understood that procedures are currently under development within CER and should be completed, to provide a clear procedure while modifications to the Grid Code are being considered.
3. The concept of **contestability** (the ability for generators to construct their own connections to the power system, for adoption by the system owner) has just been introduced for renewable energy projects in the RoI, for the transmission system only. This is an option that many project developers will find attractive. However there are several critical documents and business processes which must be created in order to implement this concept. These include legal contracts, business process for design approval, and business processes associated with approval of contractors. The Regulator may wish to take action to ensure the timely creation of these necessary documents.

4. An **annual customer service survey**, carried out by a professional external body should be initiated. This will give an avenue for more focussed (and hopefully constructive) feedback on the manner in which system operators interact with the wind industry. The concept can be extended to other system users. A properly acted upon, professionally structured approach to eliciting criticisms, suggestions and feedback can be a powerful responsive way for system operators to address the issue of customer service.

In addition to the points listed above, the issue of **expected curtailment** should be addressed. The principle of curtailment due to Remedial Action Schemes or similar is discussed in Section 5. This can be termed “Forced Curtailment”, as it is driven by random or at least very infrequent events.

However it is also possible for a wind farm developer to accept “Expected Curtailment”, i.e. due to conditions that can be expected to occur with an intact network. For example, a wind farm may accept curtailment in conditions of low local loads (e.g. overnight in summer) and high ambient temperatures (e.g. “summer” rating of overhead lines). Such curtailment could be initiated by the system operator or automatically, or even by a timeclock. The wind farm operator may be happy to accept this constraint, as the probability of achieving full output from the wind farm overnight in summer is very low, and so the effect on annual production may be acceptable in economic terms. Either the wind farm can be disconnected, or (better) the maximum output is temporarily reduced.

More complex schemes could take ambient temperature or wind speed into account, in order to determine a “dynamic” rating for an overhead line for example. However this would be considerably more complex to implement in a reliable manner.

It is not clear to GH if there is any statutory or regulatory impediment to this ‘expected curtailment’ principle, in either jurisdiction. Therefore the Regulators may wish to review this issue, and if feasible incorporate this principle, where necessary, in the formal documentation (e.g. Grid Codes and similar) and in the guidance produced by TSOs and DSOs for parties seeking connections.

## 2.12 Summary

At present the installed capacity penetration level of wind generation on the island of Ireland is approximately 2.4%, meeting approximately 1.5% of the gross electricity consumption. If the renewable energy strategy being promulgated by both jurisdictions is successful the capacity penetration level is predicted to rise to about 16% by 2010.

Three ‘target years’ have been chosen for the subsequent tasks (2005, 2007, and 2010). These dates are based on the timescales of current renewables policies, and the regulatory timetable for price control review.

The current levels of wind penetration are low but are visible, in terms of impact on the power system, to the TSOs in RoI and NI. The operators and planners have many potential concerns about the anticipated increases.

The island of Ireland is possibly unique, in facing high wind penetration on an electricity system that has only a relatively low-capacity link (the Moyle interconnector) with other systems. Denmark, northern Germany and windy areas of Spain have relatively high-capacity links to other areas. This raises technical issues, for which a range of technical, commercial and regulatory solutions appears to be available.

TSOs are calling for the adoption of a prudent approach, through grid code requirements (Section 2.4). This will require an investment in and development of new technology by wind project developers and wind turbine manufacturers, and may imply significant costs for some wind turbine technologies.

If the wind industry can respond successfully to these new technical requirements the only technical limit to overall wind penetration on the island, aside from transmission/distribution limitations discussed in subsequent sections, will be set by the requirement to maintain a generation adequacy standard acceptable to customers. However, it is economically beneficial for some of these requirements to be met by conventional generation rather than wind generation.

Forecasting is an important issue, and further development will be beneficial. The argument for this is economic rather than technical: it will be possible to operate the system at higher wind penetration levels without improvements in forecasting, but with increased costs. Regulators should ensure that work in this area by system operators is supported and financed properly. ESB National Grid and SONI should consider a joint approach to wind forecasts. This would most certainly cost less, and there appear to be no insurmountable confidentiality issues.

The contribution of wind to generation adequacy should be reviewed as further operating data from wind farms is obtained. Recommendations for this analysis are suggested.

Variability of the output of wind farms is not to be confused with unpredictability. Analysis of operating data shows the variation that may be expected over different timescales. A method for estimating the worst-case variation is presented.

Some recommendations are made, primarily on administrative issues, which should at little cost assist in the process of achieving the targets in each jurisdiction.

### 3 TASK 2: WIND RESOURCE & WIND FARM LOCATION

Assumptions on the size and location of wind energy projects are made to provide a context for network modelling in later tasks. Numerous studies have quantified the wind energy resource for parts of the Republic of Ireland and Northern Ireland, and, rather than repeat such an exercise, the emphasis in this study is to draw on relevant recent and ongoing work.

Policy issues are addressed in Section 3.3.

This section summarises relevant resource studies and other pertinent activities.

#### 3.1 Previous Work

##### 3.1.1 Onshore wind

###### **European Wind Atlas. 1989 [5]**

Data from 10 meteorological stations in the Republic and one in Northern Ireland formed the basis of broad estimates for 50m agl (above ground level) annual mean wind speeds. Wind speeds are illustrated as bands on a map, the general pattern of which were informed by large-scale weather patterns. While relief-induced variations are not mapped, relative wind speed up- or downscaling within each band is presented for five different topographic conditions.

Wind speeds are generally highest for the west and north coast, and lowest inland of the South east corner of Ireland (around Kilkenny, Laois, Offaly and Tipperary), although eastern and central hills and ridges and coastal areas are assumed to have higher wind speeds than areas of the west with sheltered terrain.

###### **Total Renewable Energy Resource in Ireland. 1997 [6]**

For the Republic, onshore 45 m agl wind speeds for each 1 km square were estimated from meteorological station data used in the European Wind Atlas. Wind speeds varied according to nearest meteorological station, elevation, land/water surface roughness differences and slope orientation. Squares were populated with 600 kW turbines up to 9 MW/km<sup>2</sup>, and energy yield estimates derived for the:

- theoretical resource (entire land populated with turbines);
- feasible resource (removal of built-up and other technically-infeasible areas);
- and accessible resource (further removal of environmentally-constrained areas).

Only those squares with wind speeds of 7 m/s or above were considered. Results for the accessible resource by county are reproduced in Table 3.1.



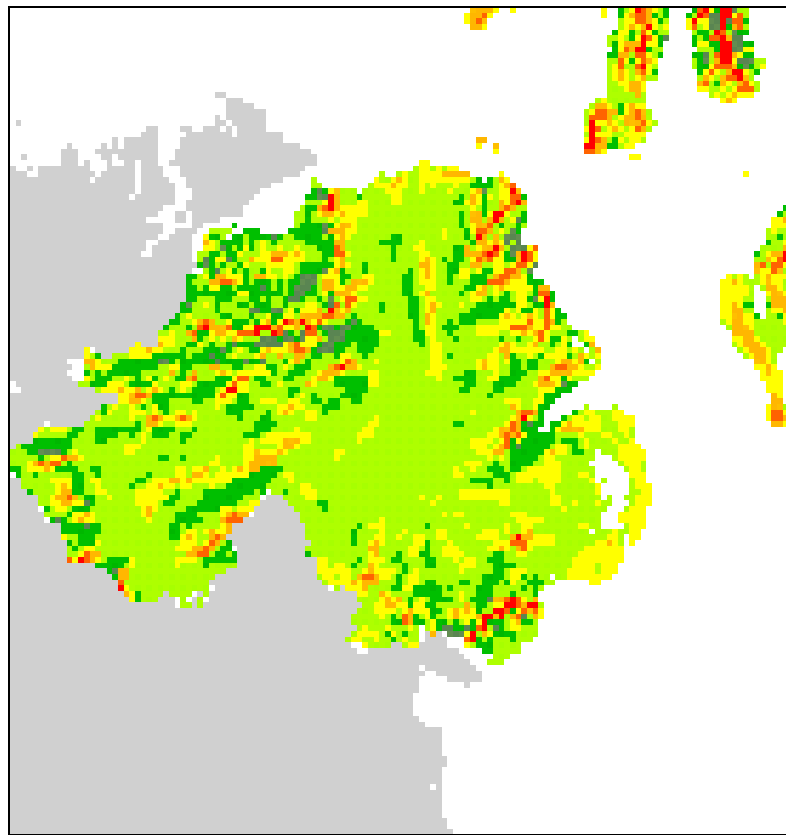
	Capacity (GW)	Energy (TWh/yr)	% energy
<b>Cork</b>	7.4	45.3	13.1
<b>Kerry</b>	9.0	24.5	7.1
<b>Meath</b>	9.8	23.8	6.9
<b>Donegal</b>	8.4	22.4	6.5
<b>Wexford</b>	8.1	19.9	5.8
<b>Tipperary</b>	6.9	18.2	5.3
<b>Cavan</b>	6.8	17.0	4.9
<b>Wicklow</b>	5.3	15.1	4.4
<b>Westmeath</b>	6.3	15.0	4.3
<b>Laois</b>	5.5	14.4	4.2
<b>Monaghan</b>	5.8	14.4	4.2
<b>Kildare</b>	5.0	12.6	3.7
<b>Kilkenny</b>	5.0	12.1	3.5
<b>Waterford</b>	3.9	10.0	2.9
<b>Offaly</b>	4.0	9.5	2.8
<b>Leitrim</b>	3.3	8.1	2.4
<b>Clare</b>	3.0	7.5	2.2
<b>Sligo</b>	3.0	7.5	2.2
<b>Longford</b>	3.1	7.4	2.1
<b>Limerick</b>	2.6	7.0	2.0
<b>Carlow</b>	2.7	6.7	1.9
<b>Louth</b>	2.6	6.5	1.9
<b>Roscommon</b>	2.7	6.3	1.8
<b>Galway</b>	2.0	4.9	1.4
<b>Dublin</b>	1.7	4.4	1.3
<b>Mayo</b>	1.8	4.4	1.3

**Table 3.1 Accessible resource from [4]**

High wind speeds were modelled along much of the west and north coast, as well as for large areas of Wicklow and parts of Waterford, Tipperary and the border between Laois and Offaly. Environmentally sensitive areas do tend to coincide with high wind speed areas, reducing the modelled accessible resource in these counties.

#### **Renewable Energy in the Millennium. The Northern Ireland Potential. 1999. [7]**

Figures for the onshore wind resource in Northern Ireland are taken from [8], (dated 1997), which uses the ETSU-modified NOABL UK database of 1 km square wind speeds to estimate the resource under a variety of scenarios. It gives a technical resource of some 106 TWh/yr and an accessible resource of 56 TWh/yr. A breakdown by county is not provided, but the NOABL wind speed map shows higher wind speeds in hilly areas across the region (see Figure 3.1 below, where the highest wind speeds are shown in red).



**Figure 3.1 Northern Ireland NOABL wind speed map.**  
(© ETSU for the DTI)

### **A Renewable Energy Development Strategy – Wind Energy [9]**

Resource estimates were made for the Irish Central Borders area, defined as Armagh, Dungannon and Omagh Districts and County Fermanagh in Northern Ireland, and County Cavan, Monaghan, Sligo, Donegal and Leitrim in the Republic of Ireland. A wind speed for each 1 km square of the study region was estimated on the basis of site altitude, extrapolating from some on-site measurements in the area. Energy yields were derived for unconstrained and constrained scenarios (the latter constrained by practical considerations and environmental designations). Results are reproduced in Table 3.2.

	Unconstrained (TWh/yr)	Constrained (TWh/yr)
<b>Donegal</b>	58.4	18.3
<b>Omagh</b>	18.5	7.5
<b>Cavan</b>	14.4	7.0
<b>Fermanagh</b>	15.3	6.6
<b>Sligo</b>	10.6	6.3
<b>Leitrim</b>	13.9	6.3
<b>Dungannon</b>	5.1	4.0
<b>Monaghan</b>	5.0	3.7
<b>Armagh</b>	3.5	3.2

**Table 3.2 Resource estimates from [9]**

### 3.1.2 Offshore wind

#### European Wind Atlas

Results for the European Wind Atlas have been extrapolated to produce an offshore wind resource map for Europe.

#### Assessment of Offshore Wind Energy Resources. (2000) [10]

For the Republic of Ireland and Northern Ireland, data from coastal and inland met stations were used to derive coefficients for mathematical modelling of offshore wind speeds. Contours of 50 m annual mean sea level (amsl) wind speeds out to 12 nautical miles offshore (territorial waters) are presented. Energy yields were derived for 1.65 and 3 MW turbines at a spacing of one machine per 500x500 m square for a number of distance offshore and depth-limited scenarios. A summary of the results is shown in Table 3.3: development is assumed to take place up to the water depth shown, and at, or further than, specified minimum distances offshore.

Water depth [m]	Distance from shore [km]	1.65 MW turbines		3 MW turbines	
		Energy NI (TWh/yr)	Energy RoI (TWh/yr)	Energy NI (TWh/yr)	Energy RoI (TWh/yr)
50	2	20.9	142	36.9	264.2
50	4	14.4	96.9	25.4	170.5
50	7	8.6	59.4	14.8	104.9
20	2	3.7	31.5	6.5	55.5
20	4	1.1	14	2	24.5
20	7	0.3	7.1	0.6	12.4

**Table 3.3 Offshore resource summary**

While the study does not attempt to identify specific sites, depth is a determining criterion with the majority of shallow (up to 20 m depth) sites situated on the east coast of Ireland.

#### Assessment of the Wind Resource off the East Coast of Ireland, 2001. [11, 12]

Meteorological station data from the European wind atlas was used to initialise the widely used WAsP wind flow modelling package. A 500 m grid of 50, 75 and 100 m wind speeds was generated for the area of interest – namely out to 20 km offshore from Dublin to Wexford, which takes in four of the five foreshore licensed blocks in the Republic of Ireland. Capacity and energy yields are then estimated for each exploration block based on 4, 2 MW turbines per km<sup>2</sup>. The results are reproduced in Table 3.4 below.

Exploration Block	Capacity (MW)	Energy (TWh)
Kish & Bray	320.0	1.2
Codling & India	1696.0	6.2
Arklow	304.0	1.1
Blackwater	544.0	2.0

**Table 3.4 Offshore resource estimates for the East coast**

## **3.2 Work Underway**

### **Irish Wind Energy Atlas**

The work for this study is now complete. It updates the Irish section of the European Wind Energy Atlas, employing additional monitored data to initialise the modelling. A publication date is not available. Further information can be found in [13].

### **Irish Wind Energy Digital Atlas**

The Department of Public Enterprise, Ireland, issued a tender in September 2001 for production of a map-based digital wind resource database for the Republic and Northern Ireland. Objectives as stated in the tender were to make use of modelled and monitored data, and be readily updateable, and interactive with other geographical information such as protected areas and grid information. The contract was awarded to ESBI and Truwind, and it is anticipated that the atlas will be available in March 2003.

### **Northern Ireland resource and grid study**

Commissioned by the Northern Ireland Department of Enterprise, Trade and Investment (DETI), administered by Northern Ireland Electricity (NIE) and overseen by a Steering Group, a study was conducted in parallel with this study to generate up-to-date renewable energy resource estimates for Northern Ireland, and to consider the grid-related constraints to accommodating this resource. The final report is awaiting publication.

## **3.3 Policy Considerations**

### **3.3.1 Background**

#### **Republic of Ireland**

In its Green Paper on Sustainable Energy [14], the Irish Government set a target of an additional 500 MW<sub>e</sub> of renewable energy for the period 2000-2005. Most of this is expected to come from onshore wind. This is in addition to AER III projects, which were not commissioned at the time of the Green Paper. The AER (Alternative Energy Requirement) competitive bidding process results in the award of power purchase contracts, under which all the output of the wind farms are purchased at guaranteed prices for up to fifteen years.

To date, projects have secured finance to build wind farms on the strength of:

- a 15 year AER Power Purchase Agreement
- an EU ENERGIE (formerly THERMIE) Power Purchase Agreement plus grant aid
- a sales agreement with a licensed green electricity supplier having access to 100% of the electricity market.

AER and European grants involve direct intervention and a form of subsidy, paid for by customers through a Public Service Obligation (PSO). The 100% access to customers is afforded to renewables in the Electricity Regulation Act, and is the closest of the three options to the “open market”.

The government intends to deliver the 500 MW target through the AER V and AER VI competitions. This implies that projects funded through the second and third categories above will supplement this capacity.

Figures presented by the Government-convened Renewable Energy Strategy Group show that the 500 MW target (which is for all renewables) is expected to culminate in Ireland's total installed capacity of wind reaching some 601 MW in 2005. To date, 137 MW of onshore wind is operational, with a further 354 MW with planning permission and a recently awarded AER V contract (see below).

The Department of Communications, Marine and Natural Resources has reported that it will commence a public consultation process in 2003 to inform the setting of a national target for 2010, and the market mechanisms that will be employed [28]. As more open market projects are developed, one option for government is to concentrate targeted support on less competitive technologies such as offshore wind, wave and biomass. However it is not yet clear if the open market mechanism as constructed at present is a viable long-term route to market for onshore wind.

In the medium-term, adoption of an obligation mechanism with tradeable green certificates may prove attractive – especially in view of prospective European and possibly international green certificate markets.

The EU *Directive on the Promotion of Electricity from Renewable Energy* (2001) detailed indicative targets for each of the Member States for 2010. In Ireland's case, the target for electricity produced by renewable energy in 2010 is 13.2% of gross electricity consumption. This would require an additional target of approx. 400 MW from renewable energy for the period 2005 – 2010. If this all is provided by additional wind farms, then wind generated electricity will contribute 10.4% of Ireland's electricity needs by 2010 (and 15.4% of installed capacity).

In October 2002, the Minister for Communications, Marine and Natural Resources stated that the government intended surpassing the EU indicative target [29]. This emphasises stated government ambitions contained in the National Climate Change Strategy that “*significant further expansion will be required.....having regard, inter alia to targets at EU level.*”

## **Northern Ireland**

Approximately 40 MW are operational in Northern Ireland, all of which supply under a NI-NFFO contract and which represent 100% of the wind energy contracts awarded under the

two NI-NFFO rounds. Additional projects are under development to supply anticipated new markets.

A consultation [15] issued by DETI in 2001 requested views on the future support and direction for renewable energy in Northern Ireland. A variety of support mechanisms for electricity generating technologies were discussed, with two key choices arising – a continuation of the NFFO model or a green certificate trading scheme. Latterly (February 2002), the Northern Ireland Assembly has reported on its “Energy Inquiry” [16], recommending *inter alia* the introduction of a GB-compatible Renewables Obligation, and targets for 15 and 35% of electricity supply to be met from renewables by 2010 and 2020 respectively.

### 3.3.2 Recent policy developments

#### AER V

In February 2002 the Department of Public Enterprise provided details of wind farms with a combined installed capacity of 354 MW that had secured Power Purchase Agreements under the AER V scheme. These projects will mark the first significant step in reaching the 500 MW target by 2005. Table 3.5 below shows the spread of wind energy projects across counties.

County	Capacity [MW]
Carlow	2.6
Cavan	24.3
Clare	32.1
Cork	22.1
Donegal	26.7
Galway	69.3
Kerry	39.3
Leitrim	11.9
Limerick	41.5
Mayo	21.3
Offaly	6.0
Roscommon	7.7
Sligo	38.0
Tipperary	6.2
Waterford	1.6
Wexford	3.6

**Table 3.5 AER V results by county**

It should be noted that there have been delays in finalising the PSO required before the issuing of power purchase agreements for AER V projects. This setback has been augmented by budget proposals to remove a tax incentive, which was to be utilised in the financial packages associated with a significant portion of AER V wind farms.

## AER VI

In November 2002, the Minister for Communications, Marine and Natural Resources announced preliminary details of the AER VI competition [30]. The allowance for wind energy is 470 MW, comprising 350 MW large-scale, 70 MW small-scale and 50 MW for offshore. Projects submitted under AER V are eligible to re-bid into AER VI under certain conditions.

The delivery of the Green Paper targets will be conditional on the speedy completion of the AER VI competition leading to the early issuing of power purchase agreements, together with the availability of finance in the post budget environment.

## Foreshore Licences

The Irish government Department of Marine and Natural Resources has issued foreshore licenses for seven locations, mostly off the East Coast of Ireland, from County Louth down to Wexford, and more recently for locations on the Galway and Kerry coasts. One site – Arklow Bank off Wicklow – now also has a foreshore lease for construction of a wind farm. Subject to gaining necessary environmental and other clearances, construction is planned in four phases as shown in Table 3.6, up to a total of 520 MW by the end of 2006.

Phase	Capacity (MW)	Commissioned
1	60	1 December 2003
2	60	1 December 2004
3	160	1 December 2005
4	240	1 December 2006

**Table 3.6 Arklow Bank proposed timetable**

A number of additional applications for foreshore licences are pending. Based on information from developers, the combined offshore capacity under development may be as high as 2,000 MW.

## Crown Estate Lease

The UK's Crown Estate has recently (February 2002) launched a competition to bid for an option to develop on offshore wind farm in one area off the North coast of Northern Ireland. At Tunes Plateau, north west of Portrush, County Derry, the development must be between 150-250 MW.

Construction is proposed in three phases, starting December 2005 and finishing December 2007, although this is an indicative timetable and subject to proposals from the successful bidder.

## Steering Group on the Grid Upgrade Development Programme

Set up by the Irish government in fulfilment of one of the recommendations from the "Strategy for Intensifying Wind Energy Deployment" [17], this group is presently considering

allocation of National Development Plan Funds for grid upgrades. To inform the choice of grid upgrades to facilitate wind energy, the group has, through advertisement, solicited information on proposed wind energy developments across RoI. This information has been made available to the present study by county. Due to confidentiality, further aggregation was required for presentation here, which is shown broadly by Province – see Table 3.7 (where ‘PP’ is planning permission).

Area	Full PP (MW)	Lodged PP/Appeal (MW)	Pre-PP (MW) [1]	Total (MW)
<b>Connacht + Donegal</b>	179	89	977	1245
<b>Leinster + Cavan + Monaghan</b>	47	44	103	194
<b>Munster</b>	135	107	371	613
<b>TOTAL</b>	361	240	1451	2052

**Table 3.7 DPE aggregated onshore wind projects**

[1] Developer intends to submit planning application in 2001/02 + pre-planning stage projects + projects of unknown status

### 3.4 Summary

This chapter provides a context for the remaining tasks of the present study. It allows results to be set against anticipated real increases in wind energy. Employing for the most part the DPE data, and known onshore projects in Northern Ireland and offshore projects in both jurisdictions, a working reference for each scenario year is proposed. Due to confidentiality, only aggregated data (broadly by Province, but allowing for Northern Ireland as one area) can be shown – see Table 3.8. Data is actually held at county level.

Area	Early 2002	2005 additional (1)	2005 cumulative	2007-2010 additional (2)	2007-2010 cumulative
<b>Connacht + Donegal</b>	90	268	358	976	1334
<b>Leinster, Cavan + Monaghan</b>	3	1272	1275	968	2243
<b>Munster</b>	32	242	274	371	645
<b>Northern Ireland</b>	37	78	115	578	693
<b>TOTAL</b>	162	1860	2022	2893	4915

**Table 3.8 Island of Ireland scenario years context (figures in MW)**

(1) Full Planning Permission + Planning Permission lodged/appeal + 2 (of 5) East Coast Ireland offshore projects.

(2) Projects near to submission plus more tentative projects notified to DPE or known to Ofreg + further 2 of Ireland East Coast offshore projects + Northern Ireland North coast offshore project.



## **4 TASK 3: DISTRIBUTION SYSTEM CONSTRAINTS**

### **4.1 Introduction**

This section examines the constraints on wind capacity imposed by the distribution systems.

Single wind turbines and wind farms up to tens of megawatts may connect directly to the distribution systems. This may include very small wind turbines connected at low voltage. Offshore wind farms are expected to connect to the transmission systems and so are excluded from this section. (GH is aware of one wind farm proposed for connection to the distribution system, but this is considered to be an unusual case).

#### **4.1.1 ESB system**

The distribution system in RoI is operated by ESB Networks as Distribution System Operator (DSO), and operates at 38 kV, 20 kV, 10 kV and low voltage. There are also some parts of the distribution system operated at 110 kV, but these sections are not relevant for wind generation.

Most wind farms currently in operation connect at 20 and 38 kV.

Network connections are based on a 'deep reinforcement' policy, i.e. all reinforcement works precipitated by a proposed connection are charged to the connecting party.

#### **4.1.2 NIE system**

In Northern Ireland, the NIE distribution system operates at 33, 11 kV and low voltage, with most wind farms connected at 33 kV. Operation of the distribution system is a function of SONI.

For embedded generation above 2 MW, the DSO considers that the effects of the proposed development on the entire system need to be evaluated.

### **4.2 Characteristics of Networks in Likely Areas**

From Section 3, it is seen that the most likely areas for wind development in the Republic are rural areas with low population density and therefore sparse distribution networks.

In Northern Ireland, the likely wind areas are more evenly spread and as a consequence the distribution networks are stronger and less sparse.

### **4.3 Steady-state Voltage Range and Voltage Control**

This is identified by ESB Networks as the most restrictive issue. In the absence of wind, steady-state voltage control due to conventional loads is often the limiting factor on the system.

The output of a wind farm will further affect the voltage on the local system. For this reason ESB Networks are now requesting that wind farms operate with a power factor of 0.93 to 0.95

inductive, i.e. consuming reactive power. This is contrary to utility practice in other jurisdictions, where customers are encouraged to operate at high power factor to minimise system losses. For the 10 and 20 kV systems, ESB Networks will allow wind farms to operate down to a power factor of 0.9 inductive, as this can increase the size of wind farm that can be connected before voltage control becomes unacceptable.

If the reactive power produced or consumed by the wind farm can be controlled, this can be used to compensate to some extent. The most flexible solution is for the DSOs to have remote control of the wind farm reactive power output, but this is hardly ever done at present, and GH is unaware of this being implemented on any wind farm on the ESB or NIE systems. It also may increase demands on system operators. More rudimentary but still advantageous options are:

- Reactive power output automatically controlled in response to voltage measured at the wind farm terminals (available now from some wind turbine suppliers).
- As above, but with a function equivalent to 'line drop compensation' for transformer tap changers, in order to control the voltage at some point on the network without having to measure voltage at that point (also available now from some wind turbine suppliers).
- Reactive power output automatically controlled as a function of output power.
- As above but with the characteristic able to be changed for different seasons or different times of day, either automatically or remotely by the DSOs.

The first two of this list need careful consideration to avoid conflict with other devices on the system seeking to control voltage.

#### **4.4 Thermal Ratings**

This is not often as critical a problem as voltage control, but if voltage control is removed or reduced in significance by the measures outlined above, it is likely to be the next major factor.

#### **4.5 Reverse Power through Tapchangers**

If wind generation results in the net power flow through a distribution transformer changing direction, this may cause problems for some types of tapchanger which were designed only for flow in one direction.

This is a problem in some GB distribution systems, but has not been identified on the ESB and NIE systems to date.

#### **4.6 Protection**

It is common knowledge in the DSOs that the current practice of installing ROCOF (rate of change of frequency) protection or similar for embedded generators, to detect the 'islanding' of the local system, is beneficial for the local network but presents problems on a system level, if a drop in system frequency causes embedded generation to disconnect, which then contributes to a further rapid fall in system frequency.

ESB Networks have experienced a case where the loss of one wind farm due to a fault caused others to disconnect on undervoltage.

These problems are all soluble at a cost. There is a need for interface protection for embedded generation to be revisited. Given the lead times in product development and acceptance by DSOs, this need is urgent.

The costs of interface protection can be expected to rise as more embedded generation is connected to a system. It is not possible to quantify these costs, as the solutions are not yet identified. However, it is reasonable to say that the costs of the protection equipment are not significant, i.e. the costs are very small in comparison with total project cost: such equipment is now digital, and once the software is developed the marginal cost is small. The major driver for cost is any communications channel, for example for intertripping (Section 7).

## **4.7 Power Quality**

‘Power quality’ should more correctly be termed ‘voltage quality’, as it is concerned with the quality of the voltage on the network as seen by the customer. For wind turbines, there are three main issues.

### ***Harmonics***

Any power electronic converter will result in some harmonic voltages on the network. However these can be controlled to acceptable levels, at a cost, and the more modern wind turbine contain converters, which do this remarkably well.

The technical issues are well understood and quantified. Test and measurement procedures are now available in an EN standard [18], which allow DSOs or wind farm developers to calculate the effect of a proposed development and compare the result with the DSO’s published requirements.

### ***Flicker***

This phenomenon is the result of rapid fluctuations in power or reactive power, causing rapid fluctuations in voltage, sufficient to cause perceptible ‘flicker’ of lighting.

Again this is now well understood, and quantifiable through [18]. Wind turbine suppliers are aware that this is an issue that has to be controlled, and modern variable-speed wind turbines produce very little flicker.

### ***Voltage steps***

This is similar to flicker, except that it is produced by sudden events such as the starting or stopping of a wind turbine. The resulting voltage step can be perceptible to other consumers, but more importantly could result in the voltage at some point on the system falling outside the statutory range, until voltage control equipment on the network can operate.

As for flicker, the voltage steps expected from wind turbines in a particular location can be quantified [18], and compared with DSO requirements.

ESB Networks feel that at the lower voltage levels (10 and 20 kV), the voltage step caused by sudden disconnection of a wind farm can be a significant factor in determining the network connection costs. Disconnection of the entire wind farm will only occur in response to faults, either on the wind farm or the DSO system, and so is not strictly a power quality issue. However it can be quantified in the same way.

## **4.8 Fault Levels**

Fault level limits of existing switchgear in rural areas were not felt to be a major limiting factor by DSOs. This is contrary to the Scottish DSOs, who identified fault level limits as an important issue [35].

## **4.9 Constraining Wind Generation**

One of the solutions to some of the possible network constraints is to curtail wind generation at critical periods ('constraining off'). This is already considered by some wind farm developers, as a fixed limit: for example, 11 MW of wind capacity could be installed on a 10 MW network connection. Compared to a 10 MW wind farm, the 11 MW wind farm will produce more energy during periods of low wind speed. At high wind speeds, the output of the wind farm will be curtailed to 10 MW. However, the additional energy at low wind speeds could be sufficient to produce better overall return on investment than a 10 MW wind farm.

This principle can be extended to variable constraint limits. It is feasible for a wind farm developer to be offered connection with a specified capacity, with the caveat that under some system conditions the maximum output will be less, perhaps zero. As long as the duration and extent of the constraint can be quantified, the developer may well find this more attractive than a reduced export capacity or an increased connection cost. Penalties would apply if the constraint were breached, in the same way that the present system of Maximum Export Capacity limits is enforced.

The cost of providing this facility is not well established, but as for other communication and control proposals discussed above, it is reasonable to ignore the equipment costs. The communications cost is the major element. For the DSO, there may be an increased cost in actively managing these constraints.

## **4.10 Resource Issues**

ESB Networks felt that in some circumstances they would have been able to offer a cheaper connection to a wind farm developer seeking a connection to the distribution system, but were constrained by the resources they had available to undertake detailed investigation of a range of options.

This will become more of an issue as distributions systems fill up with embedded generation, as the combined effect of multiple generators will have to be considered.

From GH's experience of network connection negotiations elsewhere, we would concur with this view. The Regulators may wish to consider the resource issues for the DSOs.

As noted above, DSOs may also face increased costs in managing temporary constraints, and more generally, in managing a more 'active' network.

#### 4.11 Need for Distribution System Reinforcement

The scope of this study did not include detailed analysis of the limits to wind generation imposed by the distribution system, as this was felt not to be a major area of uncertainty. However it is possible to draw some conclusions from other studies on other areas.

In [35], the capacity of existing Grid Supply Points (GSPs) in Scotland to accept additional generation was analysed. GSPs are the transformer stations where the distribution systems are fed at 33 or 11 kV from the transmission system at 132 kV or above. This corresponds to the RoI and NI distinction between the distribution systems at 38 or 33 kV and below, and the transmission system at 110 kV and above.

The Scottish systems are similar in important respects to the RoI and NI systems: the population densities are similar, with sparsely-populated rural areas, and cities of similar size. The climate and electricity consumption per capita are also similar. Therefore the results reported in [35] are of interest.

The conclusions were:

- Thermal limits and fault level limits were the major constraining factors (voltage control issues were not studied due to the location-specific nature of this issue).
- 1,900 MW of new generation could be connected to the existing GSPs in the Scottish & Southern area (excluding the major islands) without significant reinforcement.
- 3,500 MW of new generation could be connected to the existing GSPs in the Scottish Power area without significant reinforcement.

The total is therefore 5,400 MW of possible new generation capacity. To draw some conclusions for the RoI and NI systems, it can be noted that Scottish maximum demand is 5,850 MW, i.e. the new generation capacity within GSPs is approximately equal to maximum demand. The ratio of new capacity to maximum demand varies from 0.83 in Scottish Power's area to 1.15 for Scottish & Southern, no doubt reflecting the different geographical circumstances.

Some caveats are necessary:

- voltage control issues were not considered, and these are identified as important issues by the RoI and NI DSOs;
- in areas which are particularly attractive to wind developers, the available capacity could quickly be exceeded;
- the figures include areas unsuited to wind development, such as cities.

However the general point is that the total figure is much larger than was expected, and much larger than the wind generation capacity envisaged at the time of the study.

Using the above factors to scale this to the RoI and NI systems, where the joint maximum demand is 6,400 MW, gives an estimate of 5,300 to 7,400 MW. This is an estimate of the generation that could be added to the distribution systems (38 kV and below) without significant reinforcement of the distribution systems. However as noted above voltage control was not considered as a constraint, and so there may well be some unquantified cost.

Strictly speaking, a correction should be made for the existing generation on the RoI and NI distribution systems. However, it can be conservatively concluded that at least 2,000 MW of wind generation, probably more, could be connected to the distribution systems without

substantial reinforcement, if (and this is critical) located ‘optimally’ from the point of view of the system. Therefore this is not a major area of concern for the next few years.

It should also be noted that a study of the GB electrical system [31] identified that an increase in renewable generation from 10% energy penetration to 20% or 30% by 2020 would incur distribution system costs in the range of 0.3 to 0.8 £ per MWh of additional wind generation (0.05 to 0.13 Eurocents/kWh). This analysis included reinforcements of the 132 kV system within the distribution costs, so a comparable figure for the RoI and NI would be lower. This level of costs supports the conclusion that this is not a major area of concern.

## **4.12 Summary**

### ***Control and communications***

As was discussed in Section 2, wind turbine manufacturers are developing means by which greater control is available over factors such as reactive power, peak power output, and ramp rate. These facilities are being developed in response to the requirements of transmission system operators, but there is no reason why the same facilities cannot be provided on wind turbines connected to distribution networks. Indeed, it is likely that TSOs will require large wind farms connected to distribution systems to meet at least some of these requirements. Today, all but the smallest wind farms (single turbines or clusters of two or three) have a SCADA system providing information on the operation of the wind farm, and some rudimentary control functions. When improved control software and hardware is developed for large wind farms, it can also be utilised at almost zero marginal cost on small wind farms. Therefore it is concluded that DSOs should define the control and monitoring functions they require for a range of possible wind farm sizes. These functions may be a subset of those for transmission-connected wind farms.

The exception to this is the communications channel. The cost of this is insignificant for a large project, but possibly significant for very small projects and single machines. To provide channels of sufficient security and capacity to meet the standards of the DSOs is estimated to cost €8k per wind farm per year, decreasing after 10 years. It seems reasonable that small wind farms or single wind turbines should not require a communications channel to the system operator, at least until the total capacity of ‘uncontrolled’ wind generation reaches a certain level. This breakpoint needs to be considered by the DSOs, TSOs and the Regulators. Wind farms without a secure communications channel would be unable to meet some of the likely Grid Code requirements, and so the DSOs and TSOs need to consider, for each of those functions, how much of the total wind generation must be fully compliant.

### ***Interface protection***

There is a need for DSOs to revisit interface protection requirements, especially for rate-of-change-of-frequency protection. Alternatives may be possible if communications channels between DSO and wind farm are available.

### ***Effort available for investigating connection options***

The system operators and owners will face increased costs for the investigation of connection options for all embedded generators. This is significantly more complex than investigation of connection options for load customers, because of the strong effect of connection cost on project size, and because of the additional control which is expected to be available from wind projects (and probably also other embedded generators, if required). The Regulators may wish to consider the resource implications for the DSOs.

***Effort available for managing more active networks***

Similarly, the DSOs may be facing a situation where they are required to manage their networks more 'actively', i.e. increased manual supervision of the state of the network, in particular voltage levels, and increased use of automatic control devices. This is likely to increase the operational and management costs, and Regulators may wish to consider for the resource implications.

***Published guidance by DSOs***

An indication of the areas of the distribution systems, which have capacity for new generation, would be useful for developers, and is also likely to reduce the workload on the DSOs. This was done in [35] and is now continued in the annual Long Term Distribution Statements produced by the Scottish DSOs. It is recommended that the DSOs and Regulators consider implementing a similar arrangement.

An additional benefit of this is that the 2000 MW figure conservatively estimated in Section 4.11 can be determined more accurately.

***Small wind turbines***

Small and very small wind turbines will generally face higher connection costs per MW, but from the analysis above there is no issue where the size of the individual turbine is a factor. However there is certainly an implication that some turbine technologies (principally variable speed) will have advantages, and these technologies are currently concentrated in the large wind turbine sector. Unless a serious market for small wind turbines emerges which encourages manufacturers to transfer this technology downwards in scale, small or very small wind turbines (as distinct from small wind farms of larger turbines) may not meet DSO requirements written for larger turbines.

***Costs***

The costs of distribution network reinforcement to cope with an increase in distribution-connected wind generation are not well established, due to the location-specific nature of most of the issues. However indications from other studies are that these costs are not severe.

If it is felt that costs in this area should be determined with greater accuracy, the most important area for study would be the limits imposed by the effect of new generation on voltage levels within distribution systems, and the options and costs for dealing with those limits. As this issue is affected by network design practices, separate studies for the ESB and NIE systems may be justified.

## **5 TASK 4: TRANSMISSION SYSTEM LIMITS**

### **5.1 Methodology for Study of Transmission System Limits**

The aim of this task was to identify limits imposed by the transmission systems, and to quantify the costs to remove them.

The methodology is reported in detail in Appendix 3. Important factors are reviewed here.

#### ***Network data***

The network data was provided by ESB NG and SONI for the three target years. The data provided represented the TSOs' assumptions about how the network may develop, given assumptions about how conventional generation may develop. See also Section 2.9.2. It is not expected that the results produced by using this network data will agree in detail with data presented in forecast statements produced by the TSOs, for several reasons:

- there will be differences in the network data used;
- the analyses will be based on different assumptions;
- there may be local limitations, which the analysis in this study will not include.

#### ***Placement of wind generation***

The methodology required wind to be added to the system at selected points until transmission infringements were found. This was done by identifying likely areas for wind generation, and using this to identify nodes on the combined systems where wind is most likely to be added. There was no formal method to locate the wind generation 'optimally', and therefore it is likely that alternative starting points would result in slightly different results. However, it is concluded that the overall quantities of wind generation determined would not change significantly.

#### ***Conventional generation***

The existing conventional generation, which would be running in the absence of wind, is assumed to be running when wind is added to the system. To accommodate the wind generation, the output of all the conventional generators are reduced, until the minimum level for each generator is reached. This strategy is often called a 'fuelsaving' strategy, as the benefit of the wind generation is limited to saving fuel consumed by the conventional generation. There are no savings in capital costs or fixed operating costs of conventional generation.

This is a conservative strategy, adopted in the light of uncertainty about the operating principles of a system with high wind penetration. In particular it is not at all clear what can be expected of wind forecasting in future. Of course, with confidence in wind forecasting, it would be feasible to shut down some of the conventional generation at times of high wind output, thus increasing the savings, but for prudence this has not been taken into account. The effect of this approach on costs is reviewed in Section 7.

In addition, with the same amount of conventional generation on the system, there are fewer concerns about reserve and frequency control. These aspects are discussed further in Section 6.

#### ***Characteristics of wind turbines***

The wind turbines are assumed to have the characteristics of conventional generators, i.e. to meet relevant aspects of the Grid Code requirements, including the likely modifications discussed in Section 2, but are not able to provide reserve and frequency response. This is believed to be largely achievable for new wind plant by 2005, as discussed in Section 2.



***Maximum unit size***

It is assumed that the maximum wind farm size is approximately 400 MW. This is approximately equivalent to the current maximum single infeed to the combined systems (the Moyle interconnector). The system has to carry enough reserve to cope with the sudden loss of the largest single infeed, so limiting the maximum wind farm size in this way will ensure that the reserve requirements are not increased.

This principle can only be followed if the frequency of sudden loss of output from large wind farms is low enough that the probability of two such events occurring simultaneously remains acceptably low. This appears sound.

Clearly, a large wind farm could be split into two halves, each smaller than 400 MW. In this case the connection to the network would have to be designed to ensure that both halves were independent, i.e. that no single failure could cause the sudden loss of both. This may also require reinforcement of the existing network.

**5.2 Results of Study of Transmission System Limits**

It was found that large amounts of wind capacity, more than currently envisaged, could be accepted on the 110 kV systems without significant transmission system reinforcement. This was an unexpected result. It was not necessary to use the higher-voltage systems, though one of the two scenarios in Appendix 3 demonstrated that higher-voltage systems could be used for large projects, without a major effect on the overall results.

Note that the wind generation assumed here to be connected to the 110 kV system could, and to a large extent will, be connected to the distribution systems. The use of the term '110 kV system' therefore also implies distribution systems below 110 kV. This will not affect the results of this analysis.

The results are shown in Appendix 3, and in Table 5.3.

As the conclusions for the two scenarios are very similar, only the "110 kV only" results are discussed in detail below. The key conclusion for both the 110 and 220 systems is that relatively large amounts of wind can be accommodated without system reinforcements. The results are of course a reflection of the nodes at which wind is connected in the model, but much less so than might have been expected.

**5.2.1 Target year 2005**

At the time of system minimum demand, approximately 800 MW can be connected to the 110 kV system without significant reinforcement. This depends critically on the philosophy that wind is not required to be 'firm', i.e. in the event of some fault on the system, or some planned outage, the wind generation in the area is automatically or remotely shut down, to prevent overloads to the remaining elements of the system. At this level of wind penetration, the most common contingencies (N-1) will not require wind to be disconnected, though less common contingencies may do.

Beyond 800 MW, further wind generation can be connected, and will occasionally be forced to reduce output (be 'constrained', or 'despatched') during low-demand periods, in order that the conventional generation running at the time is not forced to operate below its minimum limit. The more wind generation is added, the greater the curtailment.

As wind capacity increases further, there comes a point (estimated as approximately 3300 MW) where disconnection in the event of the most common contingencies (N-1) will start to be required. It was found that for any particular node on the transmission system, the number of contingencies that would require automatic disconnection of wind generation connected to that node was not great. Therefore the complexity, cost and reliability of a system to automatically recognise the need to disconnect the wind generation is likely to be acceptable, and certainly cheaper and faster than transmission system reinforcement.

Yet more wind capacity can be added, suffering increasing curtailment due to constraints imposed by conventional generation minimum limits, until at 3900 MW the last wind turbine could be expected to run at full output only at times of system maximum demand. Clearly this would be entirely uneconomic, and so this point is not expected to be reached. No significant transmission system reinforcement is required.

### **5.2.2 Target year 2007**

The results are very similar to 2005. Approximately 1100 MW can be connected before curtailment commences.

At the time of system peak demand, approximately 4100 MW can be connected. As noted above, this point is not expected to be reached.

### **5.2.3 Target year 2010**

Again, the results are very similar. Approximately 1200 MW can be connected before curtailment commences.

At the time of system peak demand, approximately 3900 MW can be connected. As noted above, this point is not expected to be reached.

## **5.3 Location**

The locations of the wind generation arrived at in the study are shown in Table 5.3. Each table shows two scenarios, as described in Appendix 3. As stated above, this information must be used with care: the allocation of generation to nodes was done in an iterative process that is expected to give a good estimate of the total that could be connected, but it is likely that larger capacities than noted in the Table could be connected to particular substations if they were developed earlier than other projects, and this would result in reduced capacities at other substations. Possibly a reduced total capacity would result, though this has not been investigated.

However, the total wind capacity is believed to be fairly insensitive to the starting assumptions, and this is borne out by the similarity in total capacity between the two scenarios listed in Table 5.3.

Substation	kV	110kV inputs only No Import/Export [MW]	220kV at 4 locations [MW]
RoI Arigna	110	80	120
RoI Arklow	220		400
RoI Binbane	110	120	120
RoI Bellacorrick	110	60	60
RoI Ballyshannon	110	50	0
RoI Cahir	110	180	120
RoI Carrickmines	220		400
RoI Charleville	110	150	120
RoI Dungarvan	110	200	120
RoI Doon	110	160	120
RoI Dunnstown	400		
RoI Dunmanway	110	180	120
RoI Flagford	220		400
RoI Killonan	110	50	60
RoI Knockearagh	110	180	120
RoI Kellis	220		
RoI Letterkenny	110	180	120
RoI Macroom	110	180	120
RoI Mallow	110	100	60
RoI Portlaois	110	400	180
RoI Sligo	110	150	120
RoI Trien	110	140	120
RoI Tralee	110	180	120
RoI Trillick	110	100	60
NI Ballymena	110	90	70
NI Ballinahinch	110	150	85
NI Coleraine	110	150	110
NI Coolkeeragh	275		250
NI Dungannon	110	150	120
NI Limavady	110	120	120
NI Newry	110	120	110
NI Omagh	110	130	90
NI Strabane	110	150	110
<b>Total</b>		3900	4245

Table 5.3 (I): Location of wind power capacity assuming system peak demand, 2005

Substation	kV	110kV inputs only No Import/Export [MW]	220kV at 4 locations [MW]
RoI Arigna	110	60	0
RoI Arklow	220		195
RoI Binbane	110	60	0
RoI Bellacorrick	110	0	0
RoI C. Fall	110	0	0
RoI Cahir	110	60	0
RoI Carrickmines	220		195
RoI Charleville	110	60	0
RoI Dungarvan	110	60	0
RoI Doon	110	0	0
RoI Dunnstown	400		195
RoI Dunmanway	110	60	0
RoI Flagford	220		195
RoI Killonan	110	0	0
RoI Knockearagh	110	60	0
RoI Kellis	220		
RoI Letterkenny	110	60	0
RoI Macroom	110	60	0
RoI Mallow	110	50	0
RoI Portlaois	110	60	0
RoI Sligo	110	60	0
RoI Trien	110	20	0
RoI Tralee	110	60	0
RoI Trillick	110	0	0
NI Ballymena	110	0	0
NI Ballinahinch	110	0	0
NI Coleraine	110	0	0
NI Coolkeeragh	275	0	0
NI Dungannon	110	0	0
NI Limavady	110	0	0
NI Newry	110	0	0
NI Omagh	110	0	0
NI Strabane	110	30	30
<b>Total</b>		820	810

**Table 5.3 (II): Location of wind power capacity assuming system minimum demand, 2005**

Substation	kV	110kV inputs only No Import/Export [MW]	220kV at 4 locations [MW]
RoI Arigna	110	120	60
RoI Arklow	220		400
RoI Binbane	110	120	50
RoI Bellacorrick	110	80	0
RoI C. Fall	110	50	0
RoI Cahir	110	180	100
RoI Carrickmines	220		400
RoI Charleville	110	120	70
RoI Dungarvan	110	200	100
RoI Doon	110	180	100
RoI Dunnstown	400		400
RoI Dunmanway	110	240	120
RoI Flagford	220		400
RoI Killonan	110	0	0
RoI Knockearagh	110	220	90
RoI Kellis	220		
RoI Letterkenny	110	180	60
RoI Macroom	110	180	100
RoI Mallow	110	100	100
RoI Portlaois	110	400	145
RoI Sligo	110	180	50
RoI Trien	110	120	100
RoI Tralee	110	180	120
RoI Trillick	110	100	100
NI Ballymena	110	145	75
NI Ballinahinch	110	120	120
NI Coleraine	110	150	100
NI Coolkeeragh	275		250
NI Dungannon	110	120	120
NI Limavady	110	120	120
NI Newry	110	120	120
NI Omagh	110	180	130
NI Strabane	110	180	100
<b>Total</b>		<b>4085</b>	<b>4200</b>

**Table 5.3 (III): Location of wind power capacity assuming system peak demand, 2007**

Substation	kV	110kV inputs only No Import/Export [MW]	220kV at 4 locations [MW]
RoI Arigna	110	60	0
RoI Arklow	220		250
RoI Binbane	110	60	0
RoI Bellacorrick	110	0	0
RoI C. Fall	110	50	0
RoI Cahir	110	60	0
RoI Carrickmines	220		250
RoI Charleville	110	60	0
RoI Dungarvan	110	60	0
RoI Doon	110	60	0
RoI Dunnstown	400		250
RoI Dunmanway	110	60	0
RoI Flagford	220		250
RoI Killonan	110	0	0
RoI Knockearagh	110	120	0
RoI Kellis	220		
RoI Letterkenny	110	30	0
RoI Macroom	110	60	0
RoI Mallow	110	60	0
RoI Portlaois	110	120	0
RoI Sligo	110	60	0
RoI Trien	110	60	0
RoI Tralee	110	60	0
RoI Trillick	110	0	0
NI Ballymena	110	0	0
NI Ballinahinch	110	0	0
NI Coleraine	110	0	0
NI Coolkeeragh	275	0	0
NI Dungannon	110	0	0
NI Limavady	110	0	0
NI Newry	110	0	0
NI Omagh	110	0	0
NI Strabane	110	60	60
<b>Total</b>		1100	1060

**Table 5.3 (IV): Location of wind power capacity assuming system minimum demand, 2007**

Substation	kV	110kV inputs only No Import/Export [MW]	220kV at 4 locations [MW]
RoI Arigna	110	120	60
RoI Arklow	220		400
RoI Binbane	110	120	120
RoI Bellacorrick	110	80	0
RoI C. Fall	110	100	0
RoI Cahir	110	180	180
RoI Carrickmines	220		400
RoI Charleville	110	120	90
RoI Dungarvan	110	180	150
RoI Doon	110	180	100
RoI Dunnstown	400		400
RoI Dunmanway	110	240	150
RoI Flagford	220		400
RoI Killonan	110	0	0
RoI Knockearagh	110	220	150
RoI Kellis	220		
RoI Letterkenny	110	0	120
RoI Macroom	110	180	100
RoI Mallow	110	100	100
RoI Portlaois	110	330	205
RoI Sligo	110	180	50
RoI Trien	110	120	100
RoI Tralee	110	180	120
RoI Trillick	110	0	50
NI Ballymena	110	145	95
NI Ballinahinch	110	120	120
NI Coleraine	110	170	100
NI Coolkeeragh	275		250
NI Dungannon	110	180	180
NI Limavady	110	140	140
NI Newry	110	150	150
NI Omagh	110	180	130
NI Strabane	110	200	120
<b>Total</b>		3915	4730

**Table 5.3 (V): Location of wind power capacity assuming system peak demand, 2010**

Substation	kV	110kV inputs only No Import/Export [MW]	220kV at 4 locations [MW]
RoI Arigna	110	60	0
RoI Arklow	220		250
RoI Binbane	110	60	0
RoI Bellacorrick	110	0	0
RoI C. Fall	110	60	0
RoI Cahir	110	60	0
RoI Carrickmines	220		270
RoI Charleville	110	60	0
RoI Dungarvan	110	60	0
RoI Doon	110	60	0
RoI Dunnstown	400		300
RoI Dunmanway	110	60	0
RoI Flagford	220		300
RoI Killonan	110	0	0
RoI Knockearagh	110	120	0
RoI Kellis	220		
RoI Letterkenny	110	60	0
RoI Macroom	110	60	0
RoI Mallow	110	60	0
RoI Portlaois	110	120	0
RoI Sligo	110	60	0
RoI Trien	110	60	0
RoI Tralee	110	60	0
RoI Trillick	110	60	0
NI Ballymena	110	40	0
NI Ballinahinch	110	0	0
NI Coleraine	110	0	0
NI Coolkeeragh	275	0	80
NI Dungannon	110	0	0
NI Limavady	110	0	0
NI Newry	110	0	0
NI Omagh	110	0	0
NI Strabane	110	40	0
<b>Total</b>		1220	1200

**Table 5.3 (VI): Location of wind power capacity assuming system minimum demand, 2010**



## 5.4 Discussion

This must be read in association with the assumptions described above and in Appendix 3.

The results should be compared with the capacity required to produce 10% energy penetration (1400 MW in 2010: see Table 2.1) and the estimate of projects likely to come forward (2000 MW in 2005 and 4900 MW in 2007-2010: see Table 3.8).

### *Remedial action schemes*

The wind capacity, which can be connected without significant transmission system reinforcement, is large. This is due in large part to the assumption that, in the event of a contingency (failure or planned outage of elements of the transmission system), the resulting infringements of transmission planning criteria, if any, can be dealt with by disconnecting the wind generation local to the failure. This is distinct from simply curtailing wind output, and is specifically in order to meet transmission planning criteria.

It is assumed that disconnection can be done quickly (instantaneously in many cases, certainly within 10 minutes) and reliably enough on a sufficient fraction of the affected wind capacity to alleviate the situation. The resulting loss of generation can be met by the existing reserve levels, provided the maximum wind farm capacity that can be disconnected in any one event does not exceed the current maximum single infeed (400 MW).

Such a system is called a Remedial Action Scheme (RAS) in the US, where it is used as an interim measure, sometimes for periods of years, to cope with delayed transmission reinforcement.

Undoubtedly an analysis based on the current planning criteria, including multiple contingencies, will result in a significantly reduced feasible wind capacity before transmission system reinforcement is required. The level of this reduced capacity cannot be accurately determined without substantial work outside the scope of this study, but a brief analysis is included in Appendix 6.

The recommended approach will save therefore save cost, and perhaps as importantly will avoid the considerable delays that may affect construction or reinforcement of overhead lines and other transmission system elements. Although this study is not intended to look at planning issues, it is known that permitting of new transmission lines is subject to substantial delays, at least in the Republic, and this could be a limit on the achievable wind capacity by 2005.

This approach is not possible under the existing system planning criteria to which the TSOs must work. Therefore it is recommended that the TSOs and the Regulators review these planning criteria with high priority, and consider in detail the means of implementing RAS.

Under current planning criteria, the TSOs have to plan the transmission systems for some multiple contingencies, more than the N-1 contingencies studied here. This becomes a complex, site-specific analysis and could not be done for the combined system within the scope of this project. However, these multiple contingency cases all start with a single failure or outage for planned maintenance, and in this case it will be possible to instruct local wind generation which would cause problems in the event of a further failure to disconnect for the period of the outage. Under these assumptions it is possible for wind farms to be curtailed for periods of several weeks due to planned maintenance.

***Capacity credit***

If in future it is established that wind can be credited with some capacity credit, only wind farms which are not subject to RAS, i.e. have 'firm' connections, should be eligible for capacity payments.

***Costs***

As this strategy offers significant benefits compared to system reinforcement, the likely costs of system reinforcement have not been quantified. It was noted that the dominant constraining factor was thermal limits of elements of the existing system. Removing these constraints by other means requires re-conductoring or rebuilding of overhead lines, replacement of transformers and other plant, and construction of new lines and substations.

Note that, with a 'shallow' reinforcement policy, cost savings will apply to the transmission asset owner, not the wind farm developer. The reduced risk of delay is likely to be enough to recommend RAS to developers. However, Regulators may wish to consider which party should bear the cost of lost production due to RAS.

The required protection, control and communication equipment is expected to be relatively inexpensive, as most of it will be implemented locally, often within a single substation. Costs are reviewed in Section 7. There is a question about small wind farms or single turbines, which may be connected to a distribution feeder with customers. In this case disconnection will have to be implemented close to the wind farm, requiring communication channels. However in most cases it is expected that it will not be necessary to disconnect all wind turbines associated with a substation, and so it may not be necessary to include small installations in the RAS scheme.

***Other limiting factors***

Assuming that wind turbine capabilities advance as expected, and that system planning criteria can be altered to allow RAS, the major limiting factor on wind penetration becomes the conventional generation:

- its minimum load limits, as modelled in this work;
- the connected capacity required to provide sufficient reserve;
- the confidence that can be placed in forecasting, to allow conventional generators to be shut down;
- and the speed with which conventional generation can be started.

***Comparison with location of wind generation estimated in Section 3.***

It is emphasised elsewhere in this section that the locations used in this analysis for wind generation are not particularly important. Certainly the capacities allocated to substations in Table 5.3 should not be used by project developers to select sites, or as the basis for negotiations with the TSOs. The capacities allocated to each substation are a function of the starting points: additional capacity could be added to almost any one of those substations, and is likely to result in some reduction at other substations. The important conclusion is the total capacity, which is thought to be relatively insensitive to the initial allocation of wind to nodes on the transmission system.

However, to check for relevance of the results, the capacities allocated to substations in Table 5.3 (both scenarios) were checked against the expected locations for new wind developments

derived in Section 3. In Section 3, new wind capacity was identified at the county level, but for confidentiality reasons was presented at coarser geographical resolution (Table 3.8).

It was found that the agreement at a county level was reasonable. The major exception was in Counties Galway, Mayo and Wexford. In the work of this section, these counties were allocated zero wind generation because higher-wind-speed sites were available elsewhere. However it was found in Section 3 that there are some projects proposed for these counties. The effect of this on the results of this section can be summarised as follows:

- If projects were developed in these counties (or offshore from these counties), the transmission system could accommodate some wind power in addition to the capacities stated in Table 5.3.
- This additional capacity will be small in counties Wexford and Mayo because of heavy loading of the existing transmission system.
- County Galway could accommodate more additional wind generation without reinforcement of the existing system.

The broad conclusion is that the total capacity determined in Table 5.3 is probably conservative, i.e. an underestimate.

## 6 TASK 5: IMPACT ON POWER SYSTEM OPERATION AND ANCILLARY SERVICE COSTS

An area of concern to system operators is the impact that large-scale wind generation can have on the operability of the power system. The principal issues are reviewed in this section.

### 6.1 Voltage Stability

Voltage stability is the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance. A Power System is “voltage stable” if voltages after a disturbance remain close to voltages at normal operating condition. A Power System becomes unstable when voltages uncontrollably decrease due to outage of equipment (generator, line, transformer, busbar, etc), increment of load, decrement of production and/or weakening of voltage control. Voltage control and voltage instability are local problems. However, the consequences of voltage instability may have a widespread impact. Voltage collapse is the catastrophic result of a sequence of events leading to a low-voltage profile suddenly in a major part of the Power System.

The main factor causing voltage instability is the inability of the Power System to meet the demands for reactive power in the heavily stressed system in order to keep desired voltages. Other factors contributing to voltage stability are the generator reactive power limits, the load characteristics, the characteristics of the reactive power compensation devices and the action of voltage control devices.

The addition of wind power to the network in a controlled way should have no negative impact on the operability of the Power System from the point of view of voltage stability.

Considerations of voltage stability are not relevant to the determination of the total amount of wind power (i.e. MW) that can be accepted on any given network, but they are relevant to the detailed design of the connection arrangements of individual wind-farms (i.e. some form of power factor control may be required in certain locations).

The relationship between the power imported into a local sub-network and the voltage at a representative point in that network (e.g. an important busbar) is as presented in Figure 6.1. The voltage falls as the power import is increased, and the rate of decrease of voltage accelerates at high loads.

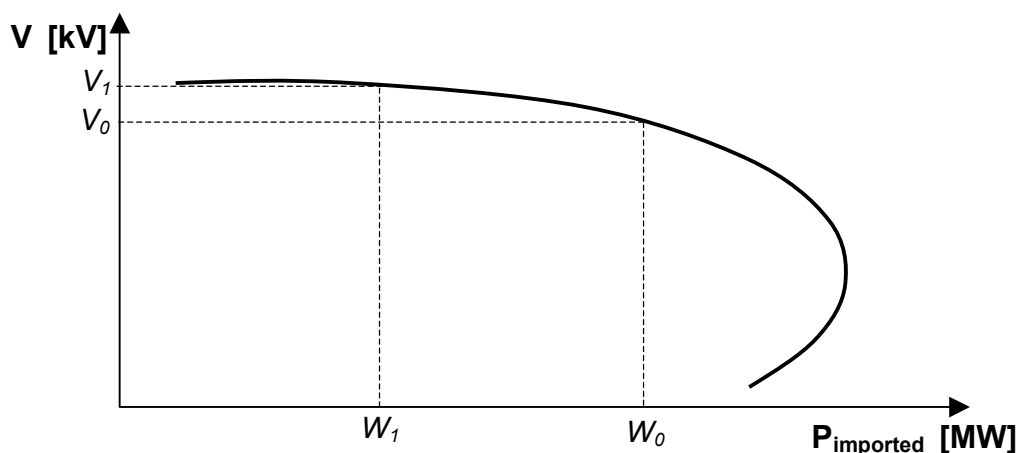


Figure 6.1 Relationship between Imported Power and Voltage (P-V curve)

Figure 6.1 shows that the voltage with no wind-power input will be  $V_0$ . This is the situation for which the network has been designed. It corresponds to the Base Case input data provided by the two TSOs. In the presence of a local wind-power input, the import power is reduced to  $W_1$  and there is a corresponding increase in voltage to  $V_1$ .

If the entire wind-power were to disappear, the power input and voltage would return to  $W_0$  and  $V_0$ .

Voltage stability (or, more correctly the risk of voltage collapse) in the steady state sense is an issue only for sections of network which are weakly connected to the rest of the system, and which have insufficient local generation feeding them. Additions of local generation (whether powered by wind turbines or by any other type of prime mover) should reduce power flows and mitigate the risk of voltage collapse. When the new local generation is not operating, the situation should be no different from the present case.

However, when connecting local generation to such a network, it is necessary to limit the size of the maximum block of generation that can be disconnected in a single, abrupt event (e.g. an electrical fault in the connection between that block of generation and the network). This must be done to eliminate the possibility of a transient dip in voltage, which could be large enough to precipitate a voltage collapse.

To conclude, voltage stability is not expected to be an issue when connecting wind power generation to a healthy Transmission System or even to a weak sub-network provided that the reactive power capabilities of new wind generators can be comparable to that of existing conventional generators (Note: this is not the case at present, but is expected to be by 2005).

## 6.2 Frequency Regulation and Reserve Requirements

### 6.2.1 Effect of wind generation on reserve requirements

At all times the power output of the connected generation to a Power System must equal the total power demand plus the total losses in the system. If there is a temporary excess of generation over load (plus losses) the system frequency will rise, and if total load plus losses exceed total connected generation, the system frequency will fall.

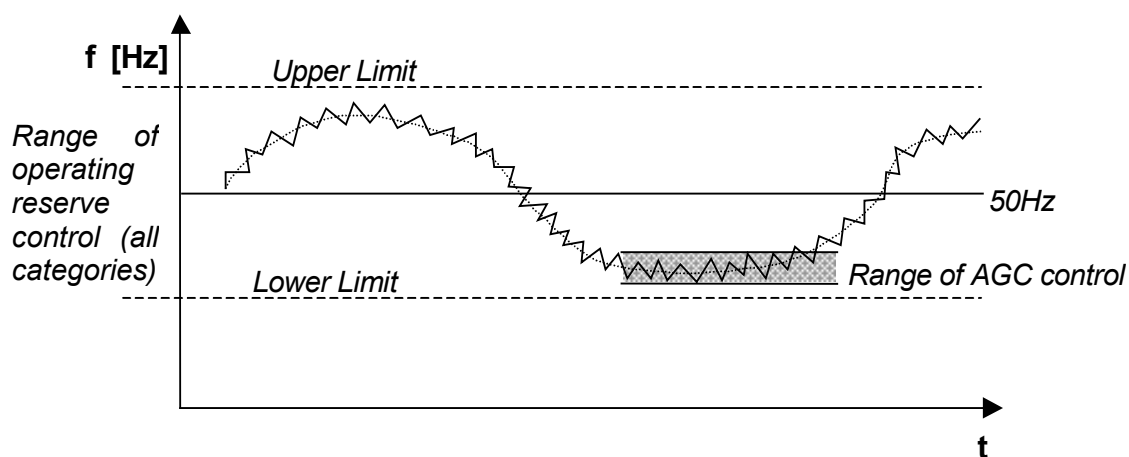
Power system operation is concerned with maintaining the Power System frequency within acceptable preset limits (e.g. 49.8 to 50.2Hz in normal operation) at all times. In order to do this, generation reserves are made available to maintain the power balance in the event of a loss of connected generation (e.g. due to a fault in a generator or in a transmission line), as described in Table 6.1 for the ESB National Grid system.

The level of reserve held is directly related to the largest single infeed into the power system, be that from conventional generation, wind-generation or interconnectors.

CATEGORY OF RESERVE	TIMESCALE OF ACTION	PURPOSE
Primary Operation Reserve (POR)	5 to 15 seconds	To arrest fall of frequency
Secondary Operating Reserve (SOR)	15-90 seconds	To restore the frequency
Tertiary Operating Reserve Level 1 (TOR1)	90 to 300 seconds	To hold the frequency while replacing some SOR which could be exhausted after 90 seconds
Tertiary Operating Reserve Level 2 (TOR2)	5 minutes to 20 minutes	Restore full operating reserve to be ready for next event
Standby Reserve (SR)	20 minutes to 4 hours	To restore the system to normality

**Table 6.1 Categories of generation reserves (ESB National Grid nomenclature)**

In addition to maintaining frequency within accepted limits in the event of faults, selected elements of primary operating reserve (Automatic Generation Control, AGC) also perform the task of micro-control of the power system frequency. This is shown in Figure 6.2 below:



**Figure 6.2 Micro-control of Power System frequency**

Wind generation inputs can be lost from the system in three ways. These are outlined below.

### ***Faults***

A windpower input can be lost abruptly (e.g. due to electrical faults in its connection to the system). The impacts of such interruptions will be exactly the same as those of interruptions to any other type of generation. Unless and until the largest block of windpower which could be disconnected by a single abrupt event exceeds the size of the largest other input to the

system (this would be the Moyle interconnector in 2005), the provisions for Primary and Secondary Operating Reserve will not be affected at all.

### ***Wind***

Windpower inputs can be lost due to changes in the wind. It is generally accepted that the wind is inherently unreliable. However, it will not disappear instantly, so any loss of power into the system due to a change in wind will not be abrupt.

It seems likely that the worst that could happen would be the loss of windpower in a particular area over a few minutes, with the prospect of the loss of most, perhaps all, windpower over the entire island of Ireland, over a period measured in hours (see Section 2.7). This is expected to be foreseen by the wind forecasts. This situation is one with which the present plant and practices should be able to cope.

### ***Interface protection***

All generators are fitted with relays, which are designed to disconnect them from the system if the rate of change of frequency exceeds a preset value. For example, on the ESB National Grid system, the limiting rate of change of frequency for conventional generators is 0.5Hz/second. Providing the relays which are fitted to wind generators are set to operate at the same rate of change of frequency as other generators, the presence of wind generators will pose no greater risk to the system than conventional generators.

This is not the practice at present in Ireland, where such relays for wind-farms are set at a more sensitive level in order to protect against “islanding”, but it is a recommendation of this report that this should be regularised to the level applicable to conventional generation.

In summary, no greater levels of provision of operating reserve will be required because of the connection of wind generation to the system.

With respect to Automatic Generation Control (AGC), the variability of wind generation output reviewed in Section 2 is not expected to increase demands on the generators providing AGC.

## **6.2.2 Contribution to reserve requirements**

Conventional steam generation assists the network in the following ways:

- Inertia. On the sudden loss of a generator, the system frequency will decrease as mechanical energy is withdrawn from all the synchronously spinning inertias on the system, i.e. synchronous generators and rotating loads. The greater the connected inertia, the slower the drop in frequency.
- Energy stored in the steam systems is withdrawn as fast as governor valves can operate, to increase the output of the thermal plant.
- The fuel input rate is increased to increase the steam output of the conventional generation.

Other plant (hydro, gas turbines) may also have some contribution. Pumped-storage systems have a major beneficial effect.

Wind turbines respond differently. The only stored energy is in the rotor inertia, and the fuel input cannot be increased at will, unless operated such that energy is lost for the vast majority

of the time. Fixed-speed turbines will provide some benefit from their inertia, provided that frequency and voltage remain within their operating limits. Variable-speed wind turbines will not ‘naturally’ provide this benefit. Therefore, if variable-speed wind turbines displace conventional generation, the total system inertia will decrease. Therefore the rate-of-change of frequency and the depth of the frequency dip caused by a sudden loss of generation will both increase.

For both wind turbine concepts, reserve is only available if the wind turbines have previously been de-loaded by the required amount. This is likely to be very uneconomic, unless it was only implemented for a few critical hours per year. This is credible, at least for Primary and Secondary operating reserve, and should be investigated further in a detailed study of operating strategies at high wind penetration. It is not possible at this stage to estimate the value of this concept. The benefits would be less wind curtailment and less fossil fuel consumption.

However, variable-speed turbines could in principal be controlled to provide the equivalent inertia. This has been shown in simulation for the DFIG concept [32], and similar techniques are likely to be feasible with direct-drive turbines. The simulation results in [32] show that the effect on turbine rotational speed and aerodynamic efficiency is not great, and so GH considers it likely that wind farms could be controlled to provide a proportionately greater equivalent inertia than conventional plant of the same rating. This could be taken a step further, to provide as much energy out of the wind turbine inertia as is possible in the earliest stages of an event (limited only by the capacity of the wind turbine drive train and power-handling components). When the rotational speed is reduced so far that the aerodynamic performance of the rotor starts to be seriously impaired, the ‘inertia effect’ would be switched off.

This clearly needs to be investigated further and demonstrated by testing. However it does appear that wind turbines may be able to offer some benefit, to counteract their inability to provide longer-term reserve. It is recommended that TSOs examine how they might best make use of this ability, and how they may specify their requirements.

### **6.3 Power Quality**

The quality of power delivered by a system is measured in terms of the level of flicker, incidences of spikes, voltage dips, etc.

The effects of wind turbines on power quality are reviewed in Section 4 for the distribution systems. As power quality problems are essentially local, and more likely on lower-voltage systems, wind turbines are not expected to cause such problems on transmission systems.

### **6.4 Dynamic Issues**

It was agreed that the scope of this work would not to include study of dynamic issues. It was hoped that other studies under way at the same time would provide some useful conclusions, and allow a decision to be made about the need for further work in this area, specifically for the combined systems of RoI and NI. However it is understood that difficulties with the detailed models have delayed this work.

From discussions within the wind industry, GH tentatively concludes that the dynamic behaviour of wind turbines that appears to be required by TSOs (as evidenced by Grid Code



requirements, draft and published) has a good chance of being provided by turbine manufacturers over the next year or so. This is insufficient reassurance on which to plan a major expansion of wind generation, and so the following actions are recommended:

- The TSOs (and possibly DSOs) define more closely their concerns about dynamic issues, including if possible requirements based on technical analysis of the needs of their systems;
- Further work is carried out to establish with the wind turbine manufacturers what their products can do and are expected to do in the near future;
- An assessment is then made of the risk to the expansion of wind on the RoI and NI systems: i.e. will this issue constrain the rate at which wind generation will be developed, such that the targets in either jurisdiction are threatened.

## **6.5 Ancillary Services**

Ancillary services are those functions provided by generators in addition to energy production.

As discussed above, it is considered likely that wind turbines will become available in the next few years which can do almost everything that conventional generators can do, at least as defined in Grid Code requirements. Therefore this section concentrates on the services that wind turbines are not expected to be able to do, or cannot do well. ('Capacity credit' is discussed in Section 7).

### **6.5.1 Black start**

Wind turbines cannot reliably contribute to getting the system running again after a catastrophic event. Some other generators can be paid for this ability, but this will not result in a significant economic penalty for wind.

### **6.5.2 Reserve**

As noted in 6.2, wind turbines could only provide reserve at the cost of a severe economic penalty. It is feasible that this may be worthwhile for relatively short periods per year, for example where it allowed a lightly-loaded conventional generator to be shut down rather than running solely to provide reserve. This is not a critical issue, but should be considered in any further study of alternative operating strategies.

### **6.5.3 Frequency regulation**

As discussed in Section 2.4.6, this can be achieved at some cost in energy production. Wind generation would be an expensive way to regulate frequency. The points made in Section 6.5.2 also apply.

### **6.5.4 Fault current**

Conventional generators provide sustained high currents during faults. Power system protection techniques depend on this fault current for the detection of faults. Wind turbines

with power electronic converters, especially DFIG types, may not do this. It is recommended that TSOs and DSOs review their need for fault current, and determine if specific requirements need to be set in Grid Codes or similar documents.

### **6.5.5 Costs of ancillary services**

For the analysis method adopted in Section 5, it is not necessary to estimate the effect on ancillary costs, as it is assumed that the conventional generation running in the no-wind case is also running when wind is added, and is therefore available to provide the normal level of ancillary services (to a good approximation). This may be an expensive operating philosophy at high wind penetrations. If some of this conventional generation were shut down, wind could provide replacement ancillary services at zero additional cost, except for reserve and frequency regulation as described above.

It appears illogical to build new plant specifically to provide reserve and frequency regulation, as this plant will be needed for only a small fraction of the year. It is likely that the economic solution is to keep conventional plant running to provide these services, and curtail wind output. The effect on fuel savings and wind production is considered in Section 7.

Nevertheless, the possibility of using part-loaded wind generation to provide these functions is intriguing, and this may be worth further study in future, as noted in Section 6.5.2. The costs of using the Moyle interconnector for frequency regulation should also be considered.

Ancillary services can, in principle, either be required of all generators (for example through a Grid Code requirement) or purchased by the TSO through a market mechanism. Market mechanisms may be most attractive for those services for which some generators are particularly suited or unsuited, compared to others. Markets for reserve and frequency response would (justifiably) put wind at a commercial disadvantage. On the other hand, a market for “inertia effect” could equally be justified, although GH is unaware of this being done anywhere before. This could, in principle, provide a (small) commercial advantage for wind: see Section 6.2.2.

It is recommended that the TSOs and Regulators consider, as a matter of urgency, whether a market for frequency response is preferred to a general Grid Code requirement for frequency response.

## **6.6 Interconnectors**

The analysis presented in this study has made little use of the Moyle interconnector. It is assumed to be carrying only marginal import or export. In reality it will appear, at least in the steady-state, as another generator, and its output may be reduced (perhaps go negative, i.e. export to Scotland) depending on wind production and contractual arrangements.

In the analysis of Section 2, it was concluded that calm periods on the island of Ireland were matched by calm periods on the west coast of Britain. GH considers it is likely that wind speeds on both sides of the Irish Sea are similar for much of the year. Therefore an interconnector constructed to carry the output of wind farms is likely to have a very low load factor, as similar penetrations of wind generation are expected on both islands.

It is therefore concluded that expansion of wind in RoI and NI does not significantly advance the case for further interconnector capacity to GB. If market conditions on each side of the

Irish Sea eventually settle down to a situation where there are substantial differences in the way in which wind is treated, this conclusion should be revisited.

In Section 6.5 it is suggested that the use of the Moyle interconnector for provision of frequency regulation in the event of high wind penetration should be considered.

## **6.7 Storage**

Storage technologies should be of interest, as they could radically change the way electricity systems are operated, and there is continuing technical development in this area. However there are no immediate problems on the RoI and NI systems that cannot be met by conventional means, and there is no new storage technology available now with a track record at utility scale, except for pumped storage. A study of new storage technologies for the RoI and NI systems would better be delayed until either a utility-scale demonstration is operating, or until it is clear that the economic penalties due to wind curtailment will become significant.

Therefore it is recommended that storage is reconsidered when it is foreseen that the wind energy lost through curtailment will become considerable, i.e. for wind capacity in excess of approximately 1500 MW (see Section 7.1).

## **6.8 Summary**

The major conclusions of this section are listed here.

Wind turbines with the capabilities anticipated in 2005 are not expected to increase system operational costs, if operated in “fuel saver” mode. A less conservative operating strategy will make more demands, and it is recommended that such alternative operating strategies be studied further.

Wind turbines cannot generally provide frequency regulation and reserve without severe effects on production. The use of conventional generation to provide these functions becomes expensive at high wind penetrations, but may be the best option. TSOs and Regulators may wish to decide whether frequency response is best provided by Grid Code requirements or by a market.

It is recommended that TSOs and DSOs define their concerns about possible dynamic issues. These should then be reviewed against the progress being made by wind turbine manufacturers, and further work undertaken if necessary.

## 7 TASK 6: ECONOMIC FACTORS

Task 6 has two separate elements to it. One is to attach some conventional costs to implications of increasing wind energy penetration identified in previous sections. The second is to comment on the possible effects of increasing market liberalisation on wind energy.

### 7.1 Economic Effects

Tasks 3, 4 and 5 are concerned with technical assessments of the effects of increasing wind penetration beyond that which can be accommodated by the existing network. This task attaches some economic costs and benefits to the effects on, and implications for, the network and the system as a whole.

Costs presented here are to supplement the technical findings – there has been no attempt to assess total costs, or compare alternative scenarios.

It is desirable, when interpreting these costs, to distinguish between costs which can be attributed to all generation, and those which are borne because of an increase in wind penetration. This is further complicated by the fact that there is in any case a requirement for new generation on the combined systems, due to load growth.

There is no requirement, in this study, for an assessment of so-called external or non-monetary costs and benefits.

The transmission system modelling presented earlier in this report shows that it is technically possible to connect approximately 4000 MW of wind onto the system, in 2005, 2007 and 2010, without any significant system reinforcements, if current planning criteria are changed. This is against a backdrop of the assumed development of the system, as described in Section 2.9.2. This “baseline” assumes for the most part that new conventional plant is required to meet increases in demand, and that some system reinforcement is required to accommodate this new conventional plant and new demand. This is the key starting point against which costs and benefits are assessed in this exercise. Costs already incurred in getting to this baseline in each year are not considered further here. Only costs incurred in accommodating wind on top of this baseline are considered.

The key implication of this assumption, which was a requirement of the study, is that it does not consider alternative ways in which the system might develop cost-effectively if a high wind penetration were the key goal of system planning. For example, it could be advantageous for some of the new conventional generation to be low-capital-cost and high-running-cost, such as open cycle gas turbines (OCGT). In the event, preliminary indications are that cost savings achieved in assuming alternative system development scenarios would not reduce *electricity system* costs significantly. This is wholly due to the assumption that there is not sufficient empirical data to allow operators to plan for a capacity credit from wind, which means that the system has to be able to accommodate wind as well as, rather than instead of, conventional generation. This situation could change if wind is shown to have some capacity credit.

Lastly, it is important to note that developments in technologies such as storage and small-scale domestic energy supplies do have the potential to significantly alter the assumptions and costs presented here. Again, this was not within the remit of this study, but further investigation is considered merited.

The main economic costs and benefits which can be distilled from the conclusions drawn in previous sections are as follows:

**Distribution system costs:** these are discussed in Section 4. It is shown from other published work that these costs are expected to be small, and are not proportionately more expensive at high wind penetrations.

**Curtailment:** under the assumptions of this study, at high wind penetrations it is necessary to curtail wind output in order to maintain minimum loads on conventional generation.

**Fuel Savings:** this is the main economic benefit of wind energy on the system, in the scenarios considered here.

**Grid code changes:** these will require additional functions to be provided by wind farms and wind turbines.

**Forecasting:** the introduction of routine wind energy forecasts will assist management of wind variability on the system in much the same way as demand profiling does for management of demand variability. Cost implications are the cost of the forecasting system itself, plus the reduced costs of reserve and frequency response.

**Remedial Action Schemes:** under the scenarios considered here, RASs increasingly become an alternative to system reinforcement required to accommodate wind. RASs require investment in communications to the system operator, and some additional equipment, the former being the more significant element.

**Ancillary services:** this category covers costs of providing ancillary services, over and above those, which are covered by the grid code changes.

**Losses:** transmission system losses are increased in the scenarios modelled.

**Capacity credit/contribution to generation adequacy:** an estimate of the possible value is given.

**Effect on other generators:** depending on market arrangements, other generators may suffer from the introduction of large quantities of wind onto the system.

Each of these categories is considered in turn in the following sections.

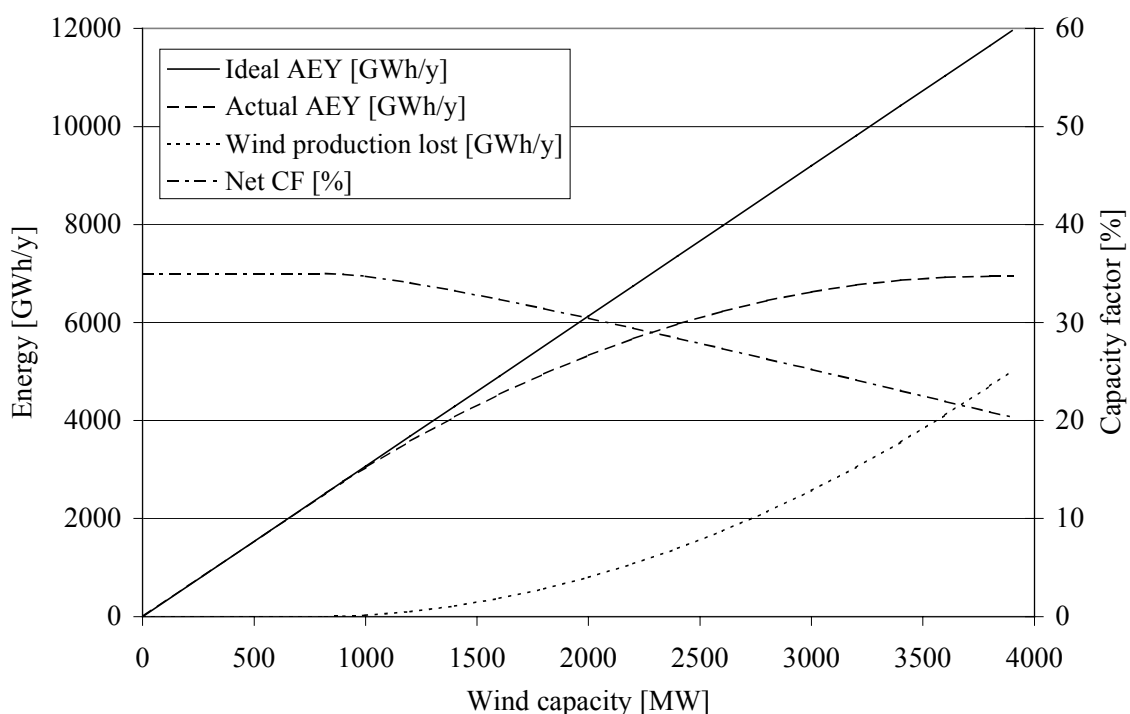
### 7.1.1 Curtailment

As has been discussed in previous sections, the analysis of feasible wind capacity on the transmission system has assumed that all conventional plant continues to run. At low load/high wind conditions, this will result in curtailment of wind generation, in order not to load the conventional generation below its minimum load limit. The effect of this is examined here.

The figure below shows the effect of increasing wind capacity on wind production. As the wind capacity increases above the maximum amount determined in Appendix 3 for the time of system minimum demand, the additional wind capacity will suffer some curtailment due to the requirement for minimum loading on the conventional generation. In this analysis it is

assumed that the capacity factor of the additional wind generation decreases linearly from its nominal value, until it reaches zero at the maximum wind capacity determined in Appendix 3 for the time of system maximum demand. This is an approximation: the true effect will not be entirely linear, and the marginal capacity factor will not fall completely to zero. In addition, the initial effects will be felt at times of lowest system demand, i.e. summer, when wind production is generally low, and therefore curtailment is less likely than assumed here. Generally these approximations are considered to produce a pessimistic result, i.e. overestimating the effect of curtailment on energy production. This is acceptable at this stage.

The unconstrained capacity factor of wind generation was assumed to be 35% for the purposes of this analysis. This assumes good sites and good turbine availability. However the trends in the figure would be very similar for other values of unconstrained capacity factor.



**Figure 7.1: Effect of wind curtailment on annual energy yield (AEY) and aggregate capacity factor (CF) (All wind on 110 kV system or below, 2005)**

It can be seen that the average capacity factor of all wind generation falls linearly from the unconstrained value to approximately 20%. At this point, approximately 40% of the potential wind output is being lost. Clearly this is a serious economic loss at very high wind penetrations.

For up to approximately 2000 MW of wind, the effect is small.

Very similar results were produced for 2007 and 2010.

### 7.1.2 Fuel savings

Scenarios representing multiple wind capacities and energy capture rates were modelled for the years 2005, 2007 and 2010, using ESBI's generation merit order model of the Irish electricity system. For each scenario the consumption of fossil fuels was determined, and this was compared to a reference case, which assumed no generation from wind. The avoided fossil fuel consumption due to the contribution of wind generation was then calculated and the avoided costs were calculated on the basis of the following fuel input prices:

UK Gas: 20p/therm at NBP ('National Balancing Point') plus transport costs. Transport costs depend on several factors but in this case add approximately 20% to the unit cost.

Coal: EUR 41/tonne

HFO: EUR 150/tonne

Gasoil: EUR 285/tonne

The fuel mix of the avoided fossil fuel was dependent on the level of wind generation and the nature of the lower merit thermal generation that was constrained off to accommodate the differing levels of wind generation.

Lower levels of wind generation as a portion of total demand resulted in the least efficient plant being forced off, whilst higher proportions began to impact on the base-load operation of cheaper CCGT and coal plant.

Note that this calculation is performed on an annual basis, i.e. it takes into account daily and seasonal variations in plant loading by using annual equivalent factors. A more detailed analysis was not felt to be necessary at this stage.

The results are presented below, for several values of assumed wind capacity. The first table shows the results for aggregate wind capacity factors of 35 %, i.e. without any wind curtailment.

Target year	Installed wind capacity [MW]	Aggregate wind capacity factor [%]	Annual fuel saving [ktoe/y]	Annual fuel cost saving [€ million/y]
2005	1000	35 %	527	75
2005	2000	35 %	1026	149
2005	3000	35 %	1530	219
2007	1000	35 %	528	82
2007	2000	35 %	1017	154
2007	3000	35 %	1500	244
2010	1000	35 %	465	74
2010	2000	35 %	951	143
2010	3000	35 %	1427	230

**Table 7.1: Annual fuel savings as a function of installed wind capacity, assuming no wind curtailment**

The second table shows the equivalent results, assuming curtailment as discussed above. For each wind capacity studied, an aggregate wind capacity factor is assumed, based on the curtailment analysis described in Section 7.1.1. Therefore the end result includes the estimated effect of curtailment of wind due to minimum loading conditions on the conventional generation.

Target year	Installed wind capacity [MW]	Aggregate wind capacity factor [%]	Annual fuel saving [ktoe/y]	Annual fuel cost saving [€ million/y]	Reduction in fuel cost saving due to wind curtailment (Note 1) [€ million/year]
2005	1000	35 %	527	75	0
2005	2000	30 %	882	128	21
2005	3000	25 %	1082	155	64
2007	1000	35 %	528	82	0
2007	2000	32 %	934	142	12
2007	3000	27 %	1169	190	54
2010	1000	35 %	465	74	0
2010	2000	33 %	896	135	8
2010	3000	27 %	1100	178	52

Note 1: difference in annual fuel cost saving between Tables 7.1 and 7.2

**Table 7.2: Annual fuel savings as a function of installed wind capacity, with expected wind curtailment**

For reference, the total fuel costs for all conventional generation in the no-wind case were estimated as:

- 2005: €936 M
- 2007: €1009 M
- 2010: €1095 M

With no curtailment, fuel savings are approximately proportional to wind capacity, as expected.

The effect of curtailment is small for 2000 MW of wind capacity, though probably sufficient to justify some modifications to conventional generation to reduce the effect.

The value of the lost wind production at 3000 MW of wind capacity is large, sufficient to pay for extensive modifications, or new plant.

### 7.1.3 Grid Code changes

These changes are aimed at requiring wind farms to provide (or have the capacity to provide), a range of ancillary services. Key amongst these are:

- Power factor control equipment.



- Fault ride through capability – implying the need for improved control functions, and possibly additional equipment such as dynamic voltage restorers.
- Dynamic response – implying the need for improved control functions.
- Steady-state response (power control) – implying the need for improved control functions and curtailment.

Curtailment costs are discussed above.

GH believes that for variable-speed wind turbines the costs of providing the required functions will boil down to improved controller hardware and software, and improved communications. These costs are largely development costs and the effect on turbine price in series production is considered negligible.

For fixed-speed turbines, particularly for stall-regulated turbines, additional hardware will be necessary in order to meet some of the requirements. These costs are very difficult to estimate at present. However, GH tentatively concludes that, if Grid Code changes proceed as anticipated, variable-speed wind turbines will dominate the market, and so the additional costs borne by fixed-speed concepts will not make a significant difference to the total price paid by the RoI and NI economies for wind generation. Therefore these costs are ignored here.

If operating strategies less conservative than the fuel-saving strategy are adopted at high wind penetrations, there would be a requirement for additional reserve and frequency response, as less conventional generation would be running at any one time. It is possible that the cheapest way to provide this is to constrain-on some conventional generation, but this has not been established. It is recommended that further work is carried out on the effects of possible less conservative strategies.

#### **7.1.4 Forecasting**

The introduction of routine wind energy forecasts will assist management of wind intermittency on the system in much the same way as demand profiling does for management of demand variability. Cost implications are the cost of the forecasting system itself, the costs of collecting production data from operating wind farms, plus the savings in conventional generation costs and costs of reserve.

GH is not aware of any published cost data for utility-scale forecasts on a commercial basis, but believes that the cost is very small compared to the economic benefits.

#### **7.1.5 Remedial action schemes**

The dominant cost is expected to be the recurring cost of leasing or rental of secure communications links. A budget cost for communications links is some €8,000 per year, per wind farm, which can be converted to a capital value of approximately €70,000. The other equipment required is not known, as the implementation of RAS schemes is not yet clear, but based on costs for protection relays and similar equipment, and assuming that some protection relays, DC supplies and similar will be required for other functions, the total cost including secure communications is expected to be in the range €100,000 to €140,000 per wind farm.

It is expected that a large wind farm, connected by a dedicated feeder to a DSO or TSO substation, may not need communication links, as the RAS equipment can be located in the

substation and directly trip the feeder circuit breaker within the substation. Only smaller installations, connected to feeders, which also supply other customers, will need secure communications from the RAS equipment in the substation to a circuit breaker at the wind farm. This possible cost saving for large wind farms has not been estimated here.

It is recommended that the TSOs and DSOs define their requirements for Remedial Action Schemes, to enable firm cost estimates to be derived.

#### **7.1.6 Ancillary services**

This category covers costs of providing ancillary services, over and above those, which are covered by the grid code changes. These are principally increased reserve requirements. If we assume that any one wind farm does not increase the worst-case, unexpected loss on the system, and that weather-related wind down-turns can be forecast, spinning reserve requirements are not altered by the addition of wind on the system. Increased reserve costs are thus centred on additional start-ups, and ramping up and down – the mix between these two being dependent on decisions on which plant to have in various states of readiness.

As noted earlier in this report, the optimum operating strategy at high wind penetrations is not known, as there is no equivalent experience anywhere, and therefore costs cannot be derived at this stage. However it is clear that with the conservative ‘fuel-saving’ strategy, there will be no increased ancillary services costs until wind penetration becomes very high: instead there are high costs for lost wind production, which are quantified above.

#### **7.1.7 Losses**

In Appendix 3, it is seen that the total demand of the combined systems (including losses) with 3900 MW of wind on the 110 kV systems is 6950 MW, at the time of system maximum demand in 2005. When there is no wind on the system, total system demand including losses is 6818 MW. Therefore the presence of 3900 MW of wind has increased transmission system losses over the whole island by 1.9 percentage points.

The worst case is in 2005: in subsequent years the effect reduces, (1.2% in 2007, 0.4% in 2010) presumably due to general load growth resulting in more consumption closer to the assumed locations of the wind generation.

At very low levels of wind production, it was found that system losses reduced (as the wind was generally located in areas of consumption), but that this trend soon reversed as wind capacity was increased.

Detailed analysis of system losses at intermediate levels of wind penetration was not carried out, but from physical principles it is estimated that the increase in system losses will approximately follow a square law, i.e. for the 2005 case discussed above, the increase in total system losses will be less than 0.5% for 2000 MW of wind.

From this it is concluded that system losses are generally increased, and for 2000 MW of wind the effect on annual losses will be less than 0.5%.

The effect of wind generation on distribution system losses was not quantified.

### 7.1.8 Capacity credit

In Section 2 it was pointed out that there is an apparent contradiction between:

- operational or meteorological data showing relatively frequent events where output of all wind generation is close to zero at times of high system demand;
- and results of generation adequacy or LOLE studies, which show some contribution from, wind generation to LOLE.

For conservatism, this report has assumed, where an assumption is necessary, that wind generation provides no capacity credit, and has recommended that this issue is studied with more input data, preferably for the whole island of Ireland.

However it is worth attempting to estimate what the value of any capacity credit might be. The best study for this purpose is the ESB National Grid Generation Adequacy Report [34]. As noted in Section 2, this determines a capacity credit for wind of approximately 20% of installed wind capacity, for up to 800 MW of wind capacity (and expected to reduce gently after that point).

To turn this into a financial benefit, it is assumed that this capacity credit will avoid the construction of new conventional generation. It is assumed this avoided generation capacity would be open-cycle gas turbine, for two reasons:

- OCGT is low-capital-cost, high-running-cost plant, and therefore gives a conservative (low) value to capacity credit.
- If wind is considered to have no capacity credit, the new conventional generation required may well be OCGT, as its low capital cost and rapid start-up time suits it for low-load-factor, 'peaky' operating regimes.

In [31], the annual cost of ownership and operation of OCGT plant is estimated as £47/kW/y. Therefore, a 100 MW wind farm, if recompensed for 20% capacity credit, could expect to receive approximately €1.5M per year. Assuming a 35% capacity factor for the wind generation, this corresponds to an additional income of approximately €5 per MWh.

### 7.1.9 Effect on other generators

The effect of increased wind generation, with the assumption that development of conventional generation continues as expected, is that the average load factor of all conventional generation will reduce. The most economic conventional generation can expect to be largely unaffected until wind penetration is very high, and less economic plant will be more severely affected. If the market arrangements for reimbursement of those generators do not accurately reflect their costs in this new operating regime, these generators can be expected to object to the expansion of wind. It is recommended that the Regulators examine the market arrangements to determine if there are any distortions which are currently not important, but which could become important when the load factor or operating regime of an existing generator is reduced significantly.

### 7.1.10 Summary of effects on costs

The above sections have discussed the effect of increased wind penetration on the costs of running the combined systems. These effects are summarised here.

***Curtailment***

This is not strictly a 'cost'. It results in the capacity factor of wind farms reducing once the total installed capacity increases above approximately 1000 MW. See Figure 7.1. This effect is zero until approximately 1000 MW, is very small up to approximately 2000 MW, and then becomes very significant.

***Fuel savings***

This is a negative cost. Full details are given in Tables 7.1 and 7.2. If the figures in Table 7.2 are used, then the effect of curtailment is automatically included. For the first 1000 MW of wind generation, the value is approximately €75 million per year.

***Grid code changes***

The costs are expected to be negligible in comparison to other items, such as the fuel savings.

***Forecasting***

The costs of developing and operating wind forecasting systems are expected to be small, and to be insignificant compared to the economic benefit they will provide. This benefit would appear as reduced use of conventional generation, thereby increasing the value of the fuel savings.

***Remedial action schemes***

The costs are estimated as €100,000 to €140,000 per wind farm. Even for a relatively small wind farm, this represents approximately €10 per kW, which is insignificant compared to the capital cost of the wind farm (see below). This is a very conservative estimate of cost, as not all wind farms will need RAS, and not all RAS schemes will need secure communications channels, which are a major part of the above figure.

***Ancillary services***

Under the assumptions made in this study, these costs are estimated above to be approximately zero until wind penetration is 'high'. The costs then depend on the operating strategy adopted, and cannot be established until the further work recommended is carried out.

***Losses***

Wind generation will increase total system losses. It is estimated that the effect will be less than 0.5 percentage points with 2000 MW of wind generation, and significantly less at lower penetrations.

***Capacity credit***

This is a negative cost. If it is established that wind generation contributes to generation adequacy, then the value will be approximately €15 per kW installed capacity per year.

***Effect on other generators***

If, as here, the benefits of wind are taken as the fuel savings, rather than the savings in electricity purchases from conventional generators, then there is no effect on other generators: they will continue to receive the payments they would otherwise have received, including all profit and overheads, minus the value of the fuel they do not have to purchase, so their financial situation will be unaltered. (Of course, if the market arrangements are imperfect, some of the conventional generators may do better, at the expense of others).

The conclusion is that the dominant elements are the fuel savings (including the effects of curtailment) and the costs of ancillary services. At low wind penetrations (certainly the first

few hundred MW) the ancillary services costs are expected to be very low. Determining ancillary services costs at higher penetrations is one of the principal reasons for recommending further study of operating strategies at higher penetrations.

It must be noted that these costs exclude the costs of developing, building and operating wind farms. If desired, this could be addressed in two ways, depending on the purpose of the economic analysis:

- A capital cost estimate of €1200 per kW, which covers all development and construction costs, and conventional network connection costs. This is a very approximate figure: clearly large onshore wind farms may cost less, and small wind farms and offshore wind farms may cost more. The accuracy of this estimate could therefore be improved for any particular scenario that is envisaged. Operating costs are in the region of €15 per kW per year.
- The difference between the selling price of wind energy and the average of all electricity sold, or the price of the best new entrant, or some similar measure, depending on purpose.

## 7.2 Ilex/UMIST report

This DTI-funded report, “Quantifying the System Costs of Additional Renewables in 2020” [40] presents some modelled system costs of increased penetration of renewables, principally wind, for the GB electricity system. Given its relevance to the present study, some comments on its scope and findings are included here.

It should be noted that the two studies are not directly comparable. The Ilex study was tasked only with investigating a range of system costs for the GB electricity network, and its methods and assumptions reflect this brief. The present study is concerned with ascertaining the technical limitations associated with increasing wind penetration on the island of Ireland, against the backdrop of an assumed set of system developments.

The Ilex study takes a scenario-based approach to quantifying system costs for 20 and 30%-level penetrations of renewables in Britain. The scenarios vary by the renewables mix, demand growth and conventional generation mix, against which additional costs are assessed. The baseline scenario assumes that new gas plant will optimally (for system costs) locate on the system to meet increasing demand. The renewables scenarios examine the implications of large amounts of wind in the North, and more geographically spread mixes of wind and biomass. Implications for replacement of old with new nuclear plant are also examined.

Costs quantified in the report are:

- Distribution
- Transmission, and
- Balancing and capacity

It is the latter two that are of most interest to the present study.

Transmission costs are essentially reinforcement costs in the report, and make up from zero to approximately a quarter of total additional costs across the scenarios. Without any prejudice to the merits or otherwise of each approach, differences between the modelling approach adopted and the present study are:

- The Ilex study adopts an N-2 contingency, triggering reinforcements earlier than may in fact be necessary. This present study employs less conservative assumptions.
- Remedial action schemes are not considered in the Ilex study – they are considered here as a means for avoiding or deferring reinforcement.

Balancing and capacity costs are comprised of:

- Security of supply costs: these are new-build CCGT and OCGT to provide capacity (for system security) and reserve services.
- Additional response and reserve
- Curtailment of wind energy output

Balancing and capacity costs make up the bulk of additional costs in the report, from approximately two thirds to all of the total additional costs, depending on the scenario. Of these, the security-related “capacity” element is the largest (over 50% in all scenarios). The nature of, and justification for, this element is not entirely clear, and is disputed by the wind industry in the UK. There is no explicit equivalent consideration in this study. It is however probably implicitly included by virtue of the conventional generation expansion plans used as a basis in the present study, which will have accounted fully for system security provisions.

A fundamental difference between the two studies is the context in which reserve is considered. In this study, reserve is provided by existing and already-planned conventional plant. Wind is added against this backdrop, and replaces fuel only, not plant. This was a relatively easy assumption to make, given that substituting wind for already-planned conventional plant was not an option under the terms of the study.

The Ilex study makes various assumptions on the retiral of existing plant and construction of new, where for the most part reserve is provided by new gas plant. There is a different view on the additional element, namely that increasing renewables penetration is the given constant, on top of which reserve is treated as an additional cost. This difference is semantics, but does contribute to the greater emphasis on reserve in the Ilex report.

On the basis of wind farm data obtained for the work, wind is apportioned a capacity credit in the Ilex study, with a sensitivity study undertaken on the effect of no capacity credit. The pertinent point from both studies is that further analysis is required for any reliable (for system planning purposes) conclusions on this point.

### **7.3 Trading Arrangements**

The purpose of this task was to review the relevance of trading arrangements to the success, or otherwise, of wind energy. A full report on the review, which was primarily a desk-based literature review, is reproduced in Appendix 7. A summary of the key points is provided here.

Wind energy, a relatively new technology in the mainstream electricity supply industry, has experienced both gains and losses under the general trend for market-based electricity trading arrangements. It has generally benefited from measures to facilitate new entrants. It has also benefited from a culture of change in the industry, as wind energy’s introduction necessitates changes in a number of activities such as system operation and grid connection.

Wind energy has arguably suffered from trading arrangements which incentivise characteristics which it does not possess – either because of currently cost-effective wind turbine design, or because of fundamental technical limitations.

The review looked at experience of wind energy in the Republic and Northern Ireland, and some selected experience abroad where there is a sizeable amount of wind on the system, exposed to liberalised market arrangements.

The review found that there was no one model for successful, and lasting, participation of wind energy in market-based trading arrangements. Experience is limited – of those countries with appreciable amounts of wind energy, there are few where wind energy has been fully exposed to any market-based arrangements (although what constitutes “market-based” varies considerably).

Very generally, the main problem identified with wind energy’s participation is with respect to requirements to accurately predict, and then deliver, volumes of energy in specified time blocks. Because of its nature, it is not possible to predict and deliver output from wind energy plant in the same way as conventional plant (this is discussed in more detail in earlier sections). Thus regimes in which plant incur financial penalties, directly or indirectly, as a result of failure to deliver to pre-notified schedules, result in a devaluation of wind energy.

Just as there is no one model for market liberalisation, there is no one approach to mitigating this effect (if indeed there is a desire to mitigate). Also, any fixes that have been applied are relatively recent, and so it is too early to say if any one is successful. It is also fair to say that another option is simply to avoid wind energy participation in trading arrangements altogether, or to develop market-based arrangements that are not centred on delivery of pre-notified amounts.

Mitigation measures taken in the jurisdictions reviewed are:

In the **Republic of Ireland**, green supplies to non-eligible customers below a certain threshold are settled on the basis of profiles, which avoids the need for half hourly metering of these customers, and avoids the expense of suppliers instigating profiling for a relatively small pool of customers. CER also has an ongoing review of trading arrangements.

In **Northern Ireland**, Ofreg has recently implemented (November 2002), the Renewable Output Factor (ROF) trading arrangements for wind power. Under ROF, a renewable supplier is required to procure 120% of the energy required to meet its customer’s demands. The extra 20% of energy provided to the system serves to compensate the Power Procurement Business for bearing the risks of the ROF arrangements. Balancing occurs on an annual basis, with a 10% carry-over imbalance allowance on this figure.

In **England and Wales**, measures for small, licence exempt generators, include the ability (up to a point) to be treated as negative demand. Ofgem is encouraging the emergence of consolidation services.

In **California**, the California Independent System Operator (CAISO) intends to introduce an arrangement whereby participating intermittent resources implement CAISO’s own forecasting system, and are cashed out against their averaged monthly deviations from submitted schedules. Basic principles for the forecasting tool were agreed through a specially-convened working group. This new system is in the process of being implemented.

In **South and East Australia**, wind energy (as well as other small generators) does not at present bid into the “National Electricity Market” pool, which is mandatory for most generators.

In **Western Australia**, a new market-based set of trading arrangements is planned, centred on bilateral contracts and a Residual Trading Market (RTM). Principles for participation of renewables are stated as there being *“no restrictions on, or penalties for, out of balance renewables; re-bidding in the RTM should be as close to real-time as practicable for operational purposes; and, in rebidding, non-despatchable renewable generators should not be limited when changing original bids in the RTM.”*

Summary observations from the review are that:

- Liberalisation appears to have been designed for participation of, and reduction of costs in, the conventional (present) generation sector.
- A range of fixes have been adopted which variously seek to accommodate, or actively encourage participation of, non-conventional generators: NETA in England and Wales, and the markets in Australia, have focused on accommodating small generators; RoI focuses on encouraging participating of competing green electricity suppliers; Northern Ireland has focused on accommodating wind energy; California has focused on encouraging the participation of wind energy. There is no one model of proven success.
- Differences probably reflect the driving force for liberalisation, whether a market is in transition, the predominant size of wind energy projects and the outlook of the Regulator.
- With the possible exception of NETA, Regulators appear to have taken a pragmatic approach to anticipated difficulties, rather than applying rigorous economic tests. In the case of NETA, the Regulator’s interpretation of his duties, the desire for a “pure” solution, and an overwhelming workload at the time of NETA’s implementation, may have been key in determining the present situation.



## **8 CONCLUSIONS AND RECOMMENDATIONS**

### **8.1 Principal Conclusions and Recommendations**

The scope of this study is wide. Therefore there are many conclusions and recommendations in the main body of this report. This section draws together the most important.

Recommendations for further work are included within the following sections.

The targets, wind resource and expected rates of development are reviewed in Sections 2 and 3. Costs and trading issues are reviewed in Section 7. Therefore the conclusions for these issues are not repeated here.

#### **8.1.1 Wind turbine technology and network operator requirements**

Wind farms have to be treated as generators rather than as negative loads on the distribution system if they are to meet the targets expected by each jurisdiction without causing major costs to the electricity systems, and without facing major delays in implementation. Wind turbines and wind farms therefore have to provide many of the functions that are currently provided by conventional generation. This is recognised by TSOs who are developing Grid Code requirements specifically for wind generation. Wind turbine manufacturers, after a slow start, are responding.

Large amounts of wind generation may connect via the distribution system, so the requirements should not be formulated solely for transmission-connected generation (though there may be justification for reduced requirements for small distribution-connected projects). For this reason, and because they may have requirements of their own, DSOs should be involved in this process.

The following points are ordered for clarity, not in order of importance.

1. TSOs and DSOs should ensure that their requirements are technically justified, i.e. address real needs of the system, and are not simply modified from requirements developed for conventional generation.
2. TSOs and DSOs should attempt to align their requirements with other system operators, so that wind turbine manufacturers have a common set of requirements to aim for (though almost certainly with different control parameter settings for different networks). It is highly desirable for type-testing of wind turbine performance carried out by third parties, if this turns out to be required, to be acceptable to all system operators.
3. Dynamic issues are considered soluble, but have not been examined here. They may represent a risk, which is presently ill-defined (see Section 6.4). The situation is developing rapidly. It is recommended that:
  - TSOs and possibly DSOs should define their concerns in detail, i.e. should provide specifications for the functions they wish to see, backed by technical arguments;
  - A review of the current capabilities of wind turbines and the future plans and development programmes of manufacturers should be carried out, possibly including interviews with the major manufacturers.
  - An assessment is then made of the risk that wind turbines will not be able to meet the justified needs of the TSOs, or will not meet them in time to allow the targets for

expansion of wind on the combined systems to be met, identifying those issues that need particular study.

4. For requirements that are readily provided by other generator types, TSOs and Regulators could consider provision via a market system rather than by a Grid Code requirement, which is mandatory on all generators. For wind, this is particularly relevant for frequency response and reserve, both of which can only be provided at the cost of wasting a significant amount of energy. Conventional generation can therefore provide these services at a lower cost, and under a market system would be recompensed for this. There is a 'half-way house' between these two options, where each generator is required to contribute towards a particular requirement, and can meet this obligation by contracting others. GH cannot see an advantage in this option that would outweigh the administrative disadvantages.
5. Frequency response and reserve capability can be provided by wind generation at the cost of wasting output. As noted above, this is expensive if provided throughout the year. However, it may be beneficial for wind turbines to provide this for limited periods of the year, when the alternative would be to curtail wind and keep conventional generation running. The use of the Moyle interconnector for these purposes should also be considered.
6. The TSOs in GB are proposing that wind farms must be capable of frequency response, but this will not in practice be exercised until all other options are exhausted, because of the waste of energy it entails. At present it appears that the *capability* for frequency response will not incur high costs for pitch-regulated wind turbines, so this is a reasonable proposal. However for stall-regulated turbines, provision of this capability will be expensive, and GH recommends that the alternative market approach for frequency response is considered. It may even be that a technical requirement, which can be seen to discriminate unnecessarily against a particular technology, could be challenged under EU competition laws. However GH is not competent in this field and raises this legal issue for consideration by others.
7. There may be some 'requirements', which are not formally recognised as such in Grid Codes or related documents, because they are always met by conventional generation by virtue of its nature. Spinning inertia, to limit the rate of change of system frequency during faults, may fall into this category. TSOs should review the Grid Codes for unexamined assumptions of this kind, and ensure the requirement is formally stated and technically justified. As an aside, it was noted in this study that variable-speed wind turbines may be able to provide an inertia effect similar to conventional generation, and could possibly have an advantage over conventional generation in this matter. However this requires further work, and demonstration on an operating wind turbine.
8. TSOs and DSOs should review their need for fault current, and decide if specific requirements should be set.
9. Wind farm operators and wind turbine manufacturers should accept that system operators will depend on the wind turbines to perform as expected, perhaps in response to sudden events that cannot be adequately simulated beforehand. Therefore a new level of professionalism will be required by the wind industry in network connection applications, and wind farm and wind turbine design. Validated models will be required (this is currently an area of some difficulty), and wind farm operators must expect system operators to take a keen interest in how the wind farm, once built, responds to transient events and to control commands.

10. Wind generation, particularly in large or transmission-connected projects, is likely to lose its 'must run' status, i.e. it will be subject to limitations by the system operators. At high wind penetrations, curtailment may be required because of limitations in the transmission system or limitations imposed by other generators. Even at relatively low penetrations, wind may be limited by caps or ramp rates. The effect on annual production will be seen by the financial institutions, which fund wind developments as an additional risk, which may be difficult to quantify.
11. Communication between TSOs/DSOs and wind farm operators will become more frequent, and it may be appropriate for some or all of the control functions to be directly controlled by the TSO or DSO. TSOs and DSOs should reach a decision on this point.
12. There seems to be no fundamental technical reason why variable-speed wind turbines cannot meet most or all of the requirements now being formulated. However this is not yet proven, and as this issue seems to be of critical importance for the high wind penetrations that may be reached on the RoI and NI systems within a few years, the TSOs, DSOs and Regulators may wish to keep abreast of developments. If a particular issue arises that cannot be provided by wind turbines, it will be important to identify it early and consider the implications.
13. Fixed-speed wind turbines may not be able to meet all of the requirements currently being discussed without additional equipment within the wind farm. This is particularly true of stall-regulated wind turbines. However, it appears that a technical solution will always be feasible, so if there is a disadvantage for particular wind turbine types, it is an economic disadvantage, not a technical one. Therefore TSOs and DSOs should avoid Grid Code requirements that specify technologies, and instead should specify performance requirements.
14. There is some justification for small projects or single turbines not having to meet these requirements, or to meet only a subset of the requirements, at least until the proportion of 'uncontrolled' wind generation reaches a set limit. There are three separate reasons for this:
  - cost of the necessary secure communications facility;
  - cost to TSOs and DSOs of managing the process;
  - cost of providing the functions, particularly for stall-regulated wind turbines.

### **8.1.2 Feasible wind capacity on the combined systems**

The island of Ireland is very unusual in its high wind resource combined with limited interconnection with other systems. Comparison with Denmark or northern Germany is misleading because these areas have larger interconnections. In addition, for political reasons Denmark has a 'must run' policy for wind and district heating, which is unlikely to be repeated in RoI or NI.

In fact, the results of this study indicate that RoI and NI could in future be more comparable to the Crete system, where currently significant wind curtailment is necessary because of the need to run conventional generation at low-demand periods.

Section 4 discusses distribution system issues (38 kV and below). It is concluded that the problems are generally understood. It is likely that, even at high wind penetrations, a large fraction of the wind generation will want to connect via distribution systems. It is

recommended that possible technical limits are investigated by a study along the lines of work completed by the Scottish network operators [35].

The issue of voltage control is location specific and was not quantified in the Scottish network study. If it is felt that it is important to quantify distribution system costs, this issue should be studied, probably via case studies on several real networks.

The feasible wind capacity is discussed in some detail in Section 5. The principal conclusions are as follows. Again, they are ordered for clarity, not in order of importance.

1. A conservative strategy ('fuelsaver') is adopted for the analysis, whereby all conventional generation that would run in the absence of wind is also run when there is wind production, but at reduced output. This saves only fuel costs but avoids concerns about provision of reserve and related matters.
2. This strategy is adequate for the purposes of this study, i.e. it demonstrates that high wind penetration is possible, but almost certainly alternative strategies (principally involving switching off conventional plant, or changing the conventional plant mix) will be more economic. It is therefore recommended that further work is done on alternative strategies. This is not time-critical, as the economic penalties of the fuelsaver strategy do not become significant until approximately 1000 MW of wind is installed. There is an argument for leaving this to late 2003 or early 2004, until more high-quality operational data is available from more wind farms, and until further progress has been made on wind forecasting. The only reason to study this issue now is if it is important, for political reasons, to establish more accurately the net cost of high wind penetrations.
3. The analysis methodology placed wind at likely locations on the transmission system until restrictions on the transmission system were encountered. It was found that large quantities of wind could be placed on the 110 kV system (some of which may in fact connect via the distribution systems below 110 kV). When higher-voltage systems were considered for large projects, similar results were found.
4. It is emphasised throughout this report that the nodes on the transmission system used in this analysis to locate wind generation are not particularly important to the end result, and should not be used by developers as indications of good connection points, or as a starting point for negotiations with TSOs. If other nodes were used, it is expected the total wind generation would be similar.
5. The results for the two scenarios and the three target years are remarkably similar. Up to 800 to 1000 MW of wind generation can be connected to the 110 kV systems before it becomes necessary, because of minimum load limits on conventional generation, to curtail wind output during low-demand high-wind periods. Further wind generation can be added, incurring additional curtailment, until at approximately 4000 MW the last wind turbine is expected to be able to run at full output only at the time of system peak demand. At this point approximately 40% of total wind production is being lost through curtailment. Clearly this is uneconomic and so this point is of theoretical rather than practical interest. No analysis was done beyond this point.
6. The results in point 5 should be put into the context of the capacity required to produce 10% energy penetration (1400 MW by 2010) and the estimate of projects likely to come forward (2000 MW by 2005 and 4900 MW by 2007-2010).

7. No significant transmission system reinforcement is required at these high penetration levels because it is assumed that wind generation does not have to be 'firm', i.e. does not require a firm connection that can withstand contingencies (failures of transmission system elements, and planned outages). In the event of a contingency, it is intended that the wind generation in the area is shut down automatically if necessary to remove overloads on the remaining elements of the system. This is termed (using US terminology for want of a better name at present) a Remedial Action Scheme (RAS). It was found that up until approximately 3300 MW of wind generation, only the less common ('N-2') contingencies would require automatic disconnection of wind generation. Beyond this point, the most common contingencies ('N-1') would also require automatic disconnection of wind generation.
8. Point 7 is a radical proposal and is not currently permitted by the transmission planning criteria under which the TSOs must work. However the benefits in deferred (or even avoided) transmission system reinforcement, and avoided delay, are considerable, and appear to justify this approach. It is therefore recommended that the TSOs and Regulators consider how the planning criteria can be modified.
9. A less radical approach may be considered as an interim measure. The transmission planning criteria can be modified to allow wind to be treated as 'non-firm' for the less frequent contingencies, but require wind to be treated as conventional generation, including transmission reinforcement if necessary, for the most common N-1 events. As noted above, the analysis shows that this avoids transmission system reinforcement up to approximately 3300 MW of wind capacity. This approach would encourage project developers to identify those points where the N-1 contingencies do not require transmission reinforcement. Regulators may wish to consider means to encourage the TSOs to identify such points and publish the information.
10. It was found that the equipment required to carry out the automatic disconnection need not be particularly complex or expensive, and will certainly be cheaper than network reinforcement. It was found that in all cases any contingency can be dealt with by disconnecting only the wind generation in the local area.
11. This strategy outlined in Point 7 does not require an increase in reserve capacity, if the largest block of wind generation that can be disconnected in this way at any one time is less than the largest generation infeed currently assumed (approximately 400 MW) .
12. Under the current transmission planning criteria, which require all generation to be treated as 'firm' and able to continue to operate in the event of all credible failures of the transmission system, significantly less wind can be connected before transmission system reinforcement is required.
13. Regulators may wish to consider whether wind farm operators should be compensated for lost production due to curtailment brought about by minimum load limits on conventional generation.
14. Regulators may wish to consider whether wind farm operators should be compensated for lost production due to curtailment brought about by transmission system contingencies. Such compensation would be unfair if the benefits of the savings in transmission system reinforcement accrued to the wind farm owners, but under a 'shallow' charging policy these benefits will accrue instead to all users of the transmission system.

15. Any cause of curtailment including those described above may conflict with the EU Renewables Directive, which requires ‘priority access’ for renewables to public electricity networks. It could be argued that the special arrangements proposed above for wind generation (more correctly, for all generation which has low load factor and is non-despatchable or intermittent) constitute ‘priority access’. However this is a legal issue on which GH is not competent to comment, and the Regulators may wish to take legal advice.

### 8.1.3 Forecasting and operational data

Forecasting of the output of wind farms is not essential to achieve high wind penetrations, but should be seen as a means of reducing system operating costs. The savings have not been quantified but are likely to be considerable as wind penetration increases, and so further development of techniques and analysis of the performance of the existing systems should be easily justified.

Joint studies on wind forecasting by both sets of network operators are likely to be cheaper and more illuminating than separate studies. A joint forecasting system will definitely be cheaper than separate systems.

It is important to collect high-quality operating data at sub-hourly timescales (fifteen-minute resolution or better) from as many wind farms as possible across the island. Currently ESB National Grid records the output of the majority of wind farms in their area at 15 minute resolution, through the metering systems. This will apply for all new wind farms, and it is also being extended to cover almost all existing wind farms. This is clearly useful. However, it is recommended that this measurement programme is extended in future to cover the following as a minimum:

- Output power (average over period, maximum, minimum);
- Nameplate capacity of wind turbines operating:
  - normally, below rated wind speed;
  - normally, above rated wind speed;
  - limited by power cap;
  - limited by positive ramp rate requirement;
  - limited by negative ramp rate requirement;
  - limited in other ways;
- Nameplate capacity of wind turbines shut down:
  - for maintenance,
  - due to low or high winds,
  - due to network failure,
  - due to network constraints.
- Site wind speed and direction

This list can be expanded and refined to suit the requirements of the system operators. It would be preferable if a common list for NI and RoI can be agreed, and ideally also for other European TSOs. Some of the items listed above (e.g. the nameplate capacity of wind turbines limited by a ramp rate requirement) are not relevant at present, but the system should be set up to record such information in anticipation of the implementation of such functions.

The information will primarily be useful for development of forecasting tools, and for system operational decisions. However it will also be useful for calculation of generation adequacy, and there are doubtless other uses.

Other parameters such as voltage and reactive power would also be useful.

This information cannot be recorded through the existing metering system, and will require:

- either 'live' communication with the system operators through dedicated communication channels (such channels may be desirable anyway to allow the TSO or DSO to adjust power setpoints, ramp rates etc.);
- or recording by the wind farm operator, with data sent to the TSO at regular intervals.

The latter is cheaper but has the disadvantage that less 'live' information is available to system operators. The TSOs should therefore consider whether the metered data is sufficient for their operational purposes. The issue is also affected by decisions on the need or otherwise for direct control of wind farms by the TSOs.

The German wind industry has benefited significantly from the requirement in one of the financial support programmes for the wind farm operators to provide operating data, and the same could be done here. Alternatively it could be made a condition of network connection, with eventual constraining-off of particular generators if data quality is unsatisfactory. Collection, quality control and analysis of this information is of benefit principally to the network operators and planners, but is also of some value to the wind farm operators and to the wind industry generally, and so there is a case for these activities being publicly funded, and the results being publicly available. It would be possible to publish the analyses without identifying individual generators, so there should be no issues of confidentiality. The Regulators may therefore wish to consider how this activity may be funded. There may be different solutions for the short term and long term.

This activity should start as early as possible.

When at least a year of such data is available, the analysis of Appendix 4 could be repeated to attempt to quantify more accurately the worst-case power fluctuations with which the systems must cope. This may be an important parameter in determining alternative operational strategies, or the requirements (and hence costs) for ancillary services.

#### **8.1.4 Capacity credit and operating strategy**

It is recommended that detailed studies of LOLE and capacity credit for wind should be undertaken regularly. The methodology and assumptions made should ideally be the same in both jurisdictions, and there is an argument for performing joint studies.

Data from as many well-distributed wind farm sites as possible should be used. Ideally these should be operating wind farms, but wind speed data recorded at potential wind farm sites (not meteorological stations) could also be used to increase the geographical coverage. Until several years of data are available, it is recommended that sensitivity studies are included to test for the effect of different wind time series, for example by time-shifting the wind time series relative to the demand time series.

These studies should examine less conservative operating strategies than the 'fuelsaver' strategy used in this study, including installing more peaking plant.

If these studies show a contribution from wind farms to generation adequacy, the Regulators should consider how this can be rewarded. Clearly no capacity payment should be made to wind generation which is 'non-firm'. No capacity payment should be made to any generator which already has an AER or NFFO premium-price power purchase agreement.

### **8.1.5 Administrative matters**

Grid Code modifications for wind generation should be progressed as rapidly as possible.

The process should ideally include representatives of wind turbine manufacturers. This may be difficult to achieve, and it is likely to be easier if handled through a grouping of the UK and Irish TSOs. Alternatively, the TSOs could consider setting up a European forum for this function. This is desirable, but could introduce severe delays.

The process of Grid Code modification should be seen to be open, and TSOs and Regulators may wish to consider how this can best be achieved.

More recommendations on administrative matters are listed in Sections 2 and 4.

## **8.2 Key Questions**

The following conclusions can be drawn for the six 'key questions' listed in the Request for Tenders. These answers are intended to summarise the general conclusions in the terms of the original scope, and should be read in conjunction with the rest of this Section.

### ***1. What is the feasible level of wind penetration, which can be safely and securely accommodated given the existing RoI and NI transmission systems and plans for their reinforcement?***

This question sets the baseline for this study, i.e. the existing plans for new conventional generation plant and reinforcements required to meet anticipated increases in demand, up to 2010. It is against this backdrop that the effects of increasing wind penetration are assessed. This leads to the adoption of a "fuelsaver" strategy for wind: increases in wind penetration replace only fuel.

Assuming that technical developments foreseen in wind turbines materialise (i.e. the ability to agree and meet transmission system operator requirements), and assuming that transmission planning criteria can be modified to permit the 'non-firm' strategy proposed, then it is concluded that no technical limit to wind penetration has been found, up to approximately 4000 MW. Instead there is an economic effect on the operation of wind farms, as additional wind farms beyond approximately 1000 MW are forced to curtail output progressively. At 4000 MW, the last wind turbine is expected to be curtailed to such an extent that it produces very little energy over the year, and the total wind generating capacity is losing approximately 40% of its annual output through curtailment. Clearly this is uneconomic, and this point is of theoretical rather than practical interest.

If transmission planning criteria are not modified, transmission system reinforcement is needed when wind capacity reaches a few hundred MW (for N-2 contingencies) and approximately 3300 MW (for N-1 contingencies).



These ‘breakpoints’ are critically dependent on the system operating strategy chosen at high wind penetrations, and the ability of the conventional generation to be operated at low loads. As there is no comparable experience elsewhere, these breakpoints must be considered very approximate.

The ‘fuelsaver’ strategy used as the basis of this study is conservative. Alternative operating strategies are likely to reduce the amount of curtailment, and should be studied further in advance of wind capacity reaching approximately 1000 MW.

***2. How is this level determined at the moment by the respective transmission system operators?***

There is no procedure currently in use for determining an acceptable level. TSOs consider each proposed development on its individual merits, including its effect on the electricity system. There have been few proposed projects of sufficient size to raise transmission system issues, and so systematic procedures to address these issues have not yet been developed.

This is partly because the operators are aware that some of the issues they are concerned about can be solved at additional cost, and so the issue becomes one of equitable determination and allocation of costs. It is also partly because the situation is changing rapidly: some of the issues may be resolved relatively rapidly and cheaply through additional requirements imposed by Grid Code modifications. Only now is information becoming available to allow TSOs to address these issues. In addition, wind turbine manufacturers are now well aware of these issues and are working to ensure their turbines can meet the likely Grid Code requirements.

TSOs assess each potential connection against certain required planning and operational criteria. Those of most relevance here are contingencies (variations on N-1 or N-2), but these criteria do not in themselves determine a maximum limit on wind capacity.

***3. What are the potential impacts of increased wind generation on system reliability and power quality?***

Power quality issues in general are gaining in importance due to pressure from Regulators, in particular harmonics, voltage steps, and flicker. Wind generation is not expected to have an effect on power quality at the transmission system level, as the issues are well understood and suitable solutions can be incorporated by wind developers at acceptable cost. Power quality is of concern at the distribution level, particularly voltage fluctuations, but again the issues are well known and can be dealt with at acceptable cost.

Reliability need not be affected by wind generation: a conservative strategy for operating the conventional generation addresses most concerns, but does not achieve all the potential economic or environmental benefits. Less conservative operating strategies are likely also to offer acceptable reliability, but as noted above, definition of the best strategy needs detailed investigation.

The high wind penetrations found in this study depend critically on reliable means of identifying events on the system (‘contingencies’) and disconnecting wind generation to prevent overloads to the remainder of the system. This requires modification of the existing transmission planning criteria as described above. It is important that this automatic disconnection can be achieved reliably, and indications are that this is likely to be the case.

#### ***4. What are the economic costs and benefits of accommodating increased wind generation?***

The costs lie in the following areas:

- Network connection and (for small wind farms) distribution system reinforcement. These costs are project specific and are not considered in this study. They are not expected to increase on a per-MW basis at high wind penetrations.
- Provision of additional functions by the wind turbine manufacturers and wind farm developers. These costs are considered to be negligible (in series production) for variable speed wind turbines, but may be significant for fixed-speed turbines, especially stall-regulated turbines. These costs have not been quantified.
- Curtailment costs when wind is curtailed for operational reasons. These costs are very significant at high wind penetrations. They depend strongly on the operational strategy.
- Forecasting functions for system operators, and associated instrumentation and telemetry. These costs are expected to be small, and much smaller than the economic benefit of improved forecasting.
- Provision of ancillary services currently provided by conventional generation, if that generation is displaced. The major items are frequency response, and reserve, which can only be provided by wind turbines at the cost of significant loss of output. The conservative operating strategy adopted in these studies ('fuelsaver' strategy) keeps conventional generation on the system so that the cost of these services does not increase. The ability of conventional generation to provide these services while operating at low load has been assumed, and should be reviewed as part of further work on alternative operating strategies.
- Protection, communications and control functions: again, the costs are expected to be very small relative to project costs.
- Electrical losses in the transmission system: the total system losses were found to increase by a small amount, approximately 0.5 percentage points for 2000 MW of wind capacity.

It is likely that at high wind penetrations, wind will have to make use of lower wind speed sites, so the economic benefits will reduce. However, costs can be expected to fall as the industry grows. From experience elsewhere, GH considers it likely that the latter effect will dominate.

There is a possibility that high wind penetrations will result in existing conventional plant being retired earlier than anticipated, causing costs to someone for 'stranded assets'. The regulators may wish to consider this issue as wind penetration increases.

The major economic benefit is the saving in fossil fuel, and this has been quantified both for the conservative operating strategy (high curtailment) and assuming a strategy that would result in no curtailment. Wind capacity of 1000 MW will save approximately €75 M per year, or 8% of the estimated fuel bill for both electricity systems, assuming a wind capacity factor of 35%.

If wind generation can be shown to provide some contribution to generation adequacy then it may attract a 'capacity credit'. The likely magnitude of this has been quantified by reference to other work. However, GH considers that the data available for a rigorous estimate is limited at present, and this matter should be considered later when more data and experience are available.

The scope of the study excluded 'external' costs and benefits. However, such potential benefits are:

- Environmental benefits (note that curtailment of wind at high wind penetrations has the side effect of reducing the environmental benefits)
- Helping to meet Kyoto obligations
- Fuel source diversity, in particular reduced dependence on gas
- Gradual increase in generation capacity which may match load growth better than large conventional generation developments.
- Employment from indigenous manufacture, installation and operation of wind turbines.

**5. *What are the potential impacts of increased wind generation, in terms of both price and quality of supply, on final customers?***

In principle, if wind generation becomes cheap enough, the impact in a competitive market will be reduced costs for final customers. Wind costs continue to reduce, but it is clear from Question 4 above that there will also be additional costs as wind penetration increases. As wind capacity increases beyond about 1000 MW, the operating strategy becomes important. Therefore, until future work is done on alternative operating strategies, it is not clear what will happen to final costs.

On the other hand, if international or EU trading in 'green certificates' proceeds, project owners in wind-rich countries will receive income. Depending on the regulatory regime, some of this value could flow to electricity consumers in the wind-rich countries.

The power systems are currently operated on the principle that there should be no reduction in quality of supply to final customers, and there seems no reason or impetus to change this principle. The effects of wind farms on quality of supply can now be calculated by rigorous methods based on independent tests of the wind turbines.

**6. *Are there any other factors which will potentially impact on the ability of the system to handle increased amounts of wind generation?***

Wind forecasting is very important to reduce operating costs and curtailment at high wind penetrations, and further development of forecasting techniques is highly desirable. The present efforts of ESB National Grid and SONI are to be applauded and should be further encouraged. As this is a research area with no immediate economic benefits for the system operators, the Regulators may wish to consider means by which these activities can be supported.

At high wind penetrations, the capabilities of the conventional generation affect wind curtailment, and so an optimum system may imply changes to the conventional generation mix.

Other factors encountered in this work which were not originally foreseen are included in the relevant section of Questions 1 to 5 above.

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## **APPENDIX 1**

### **Summary Terms of Reference**

The following summary terms of reference were agreed with the Clients.

The number of wind farms seeking connection to the electricity systems in the Republic of Ireland and Northern Ireland is increasing, and this trend is expected to continue. The anticipated levels of wind generation may well exceed, in percentage terms, the levels currently experienced in Denmark and other systems with high 'wind penetration'. System operators are concerned that the forecast wind capacity will cause unacceptable or costly effects on both electricity systems, and wind farm developers are concerned that network restrictions will cause delays or add cost to new wind farms.

With this background, the Commission for Electricity Regulation (Republic of Ireland) and the Office for the Regulation of Electricity and Gas (Northern Ireland) are co-operating in a study of the effects of increasing levels of wind generation, both onshore and offshore, on the island's electricity systems. The terms of reference of Phase 1 of this study can be summarised as follows.

- To determine, for the years 2005, 2007 and 2010, the maximum level of wind generation that can be accommodated on the island's combined power systems without modifying the development of those systems as presently planned, and in the context of existing operation policies.
- To estimate the cost implications of accommodating these high levels of wind penetration.
- To determine the most important constraints which prevent higher wind penetration.
- To evaluate the implications of removing these constraints.

Wind energy consultants Garrad Hassan will undertake this work, with ESB International Ltd and the Sustainable Energy Research Group at University College Cork as subcontractors. The study will be run from Garrad Hassan's Glasgow office.

The methodology adopted by the project team will concentrate on the transmission system (110 kV and above) and system operation issues, as this is where the significant problems are expected to occur. The combined transmission systems plus interconnections will be simulated to determine the effects of the addition of wind generation at selected points. However, distribution system effects will also be considered, in order to identify issues which may become important restrictions. The connection and system reinforcement methodologies currently used by the system operators to evaluate the impact of proposed wind farms will be reviewed and compared with practice elsewhere. Implications for the electricity markets in both jurisdictions will also be considered.

No new wind speed assessment or siting studies will be undertaken as part of this work. Instead, existing studies together with knowledge of the locations and sizes of proposed wind developments will be used.

The project team will consult with the system operators and representatives of the wind industry. An interim report will be produced early in the programme, and made available for comment from interested parties. The final report is expected in the summer, and will be followed by a presentation to invited interested parties. Depending on the conclusions, further work to study the particular issues in more detail in a further phase may be considered.

## **APPENDIX 2**

### **Comparison with NIE/DETI Study**

NIE and the Dept of Enterprise, Trade and Investment in Northern Ireland have commissioned a study to determine the realistic contribution of renewables generation to electricity production in NI in 2010, at an acceptable price to the consumer. This study was undertaken by PB Power Ltd. The study has run concurrently with the present study. It is understood that the representation of the NIE system used by both studies was the same.

The final report is awaiting approval and publication, and so discussion of its results is not possible at present.



## **APPENDIX 3**

### **Methodology For Task 4, Transmission System Limits**

#### **1. Study Assumptions**

- 1.1 Acceptable wind power capacity is that which can be connected to an intact transmission system, subject to the windpower developer's agreement to have their outputs automatically and immediately curtailed in the event of any other contingency, should the TSO consider this to be necessary.
- 1.2 Power flows to loads as stated in input data (Base Cases provided by the two TSOs for each of the three target years).
- 1.3 Conventional (and existing renewable) generators connected as stated in input data.
- 1.4 Generator maximum and minimum active and reactive power outputs as stated in the input data. For those generators for which minimum outputs are not stated, minimum active power is assumed to be 50% of rating for steam units, and 70% of rating for combined-cycle units.

Maximum and minimum reactive power for these units are assumed to be in accordance with ESB Grid Code requirements.

- 1.5 Wind generator characteristics the same as or better than conventional generators. (Note: this is not the case at present, but is expected to be by 2005).
- 1.6 Conventional generation to be displaced by wind power (until minimum active power output of conventional generation is reached) in accordance with the merit orders for the two systems (Assumption 1.8 below).

No conventional generation is disconnected from the system.

- 1.7 Inputs from hydro, turf and any wind power already connected to be considered "must run" (i.e. they can not be displaced by wind power).
- 1.8 All other generation can be displaced by wind power (but not disconnected), when it is available. The order of priority for such displacement to be:
  1. Open-cycle gas turbine.
  2. Oil-fired steam, in ascending order of size (i.e. first 60MW units, last 270MW units).
  3. Oil/gas fired steam, in ascending order of size.
  4. Gas fired steam (Aghada).
  5. Combined-cycle.
  6. Moneypoint.
- 1.9 Each of the two systems (RoI and NI) to balance generation with load + losses internally (i.e. no significant import/export in either direction under normal conditions, including through the Moyle interconnector).

## 2. Considered Planning Criteria Infringements

2.1 The following infringements to the Transmission Systems Planning Criteria were checked when connecting any wind power to the network:

- Power balance
- Voltage tolerances
- Thermal limits
- Steady-state stability
- Voltage step
- Cascading outages

2.2 Short circuit levels were not comprehensively checked because current short circuit levels in most of the proposed wind-farm connection points are well below the installed switchgear rating. In any case, individual studies should be performed for each individual wind-farm connection and remedial measures should be applied accordingly, if necessary.

## 3. Methodology and Analysis

### 3.1 Generation Limits of Acceptable Wind Power

This is best explained by an example.

(1) Let the total system demand (load + losses) be designated WTOTAL

(2) Each conventional generator has two stated values of output power

PMAX: its maximum power output, in MW

PMIN: the minimum value at which it is allowed to operate, in MW

The values of PMAX and PMIN vary for different types of plant. For example, ESB steam-driven generators can operate stably down to about 50% of their PMAX value, unless special modifications have been made (e.g. as in Moneypoint).

Let the sum of all the PMIN values for connected conventional generators be designated WMIN.

The Generation Limit of Acceptable Wind Power shall be defined as

$$W_{GEN} = W_{TOTAL} - W_{MIN}.$$

The Generation Limits of Acceptable Wind Power for the two systems, and for the island of Ireland at the time of system peak demand in 2005 are approximately as shown below.

System	Minimum Conventional Generation	System Demand (Wtotal)	Generation Limit of Acceptable Wind Power
RoI	1725	4900	3175
NI	860	1925	1065
Total	2585	6825	4240

**Table 3.1 - Generation Limits of Acceptable Wind Power in 2005  
(all values in MW)**

The values presented in Table 3.1 suggest that, if no other considerations applied, the RoI system could accept 3175MW and the NI system could accept 1065MW, without forcing any conventional generator to be disconnected, or to be operated below its minimum power output.

### 3.2 110 kV Transmission Limit of Acceptable Wind Power

This was determined as follows:

1. A map of the island of Ireland showing concentrations of potential wind power was prepared.
2. 110kV stations close to these concentrations of potential wind power were identified. A total of 27 such stations were identified.
3. A connection of 50 MW was made at each of the selected 110 kV substations, and 1350 MW was removed from conventional generation, in accordance with the Merit Order (Assumption 1.8), and without reducing the output of any generator below its PMIN values.
4. No infringements of transmission criteria were observed in (3), so the exercise was repeated for 100 MW at each of the 27 selected 110 kV stations.

Infringements were observed.

5. The acceptable 110 kV input was then maximised by redistributing inputs between 110kV substations so as to maximise the total input without incurring infringements for an intact transmission system. For NI this resulted in the Generation Limit being reached (see Table 3.1), and therefore the conventional generation totals were reduced accordingly by disconnecting some units in NI in order to fully investigate this issue.

The resulting totals for 2005 are presented in Table 3.2. Note that the total system demand does not match that of Table 3.1 due to increases in transmission system losses.

System	Output of Conventional Generation	System Demand (Wtotal)	Transmission Limit of Acceptable Wind Power
<b>RoI</b>	2040	5010	2970
<b>NI</b>	310	1970	1660
<b>Total</b>	2350	6980	4630

**Table 3.2 – 110 kV Transmission Limits of Acceptable Wind Power in 2005  
(all values in MW)**

### 3.3 Limits of Wind Power Connected at 110 kV without Import or Exports between the Systems

3.3.1 Comparisons of the results of subsections 3.1 and 3.2, above shows that:

- (1) For the RoI system, the “Generation Limit” (of Acceptable Wind Power) is greater than the “Transmission Limit”, hence the 110kV input to the RoI system is limited by Transmission System considerations.
- (2) For the NI system, the “Generation Limit” is less than the “Transmission Limit”, hence the 110 kV input to the NI system is limited by available conventional generation.

- (3) For the interconnected island system as a whole, the “110 kV Transmission Limit” is greater than the “Generation Limit”.

A further consideration is that Assumption 1.9 requires that there is no significant import or export in either direction under normal conditions, including through the Moyle interconnector.

Combining these considerations, therefore, the maximum wind power that can be accepted at 110 kV by the intact system in 2005 is as presented in Table 3.3.1.

<b>System</b>	<b>Output of Conventional Generation</b>	<b>System Demand (Wtotal)</b>	<b>110 kV Limit of Acceptable Wind Power</b>
<b>RoI</b>	2190	5030	2840
<b>NI</b>	860	1920	1060
<b>Total</b>	3050	6950	3900

**Table 3.3.1 – Maximum Wind Power that can be accepted on 110 kV System in 2005**

Following the same methodology, the maximum wind power that can be accepted at 110 kV by the intact system in 2007 and 2010 is presented in Tables 3.3.2 and 3.3.3, respectively.

<b>System</b>	<b>Conventional Generation</b>	<b>System Demand (Wtotal)</b>	<b>110 kV Limit of Acceptable Wind Power</b>
<b>RoI</b>	2325	5275	2950
<b>NI</b>	836	1971	1135
<b>Total</b>	3161	7246	4085

**Table 3.3.2 – Maximum Wind Power that can be accepted on 110 kV System in 2007**

<b>System</b>	<b>Conventional Generation</b>	<b>System Demand (Wtotal)</b>	<b>110 kV Limit of Acceptable Wind Power</b>
<b>RoI</b>	3055	5685	2630
<b>NI</b>	800	2085	1285
<b>Total</b>	3855	7770	3915

**Table 3.3.3 – Maximum Wind Power that can be accepted on 110 kV System in 2010**

Maximum wind power that can be connected to the 110 kV intact system in 2010 is less than in 2007. This result comes from eliminating two 110kV stations (in Donegal) as possible connection locations. This was necessary as it was found that in 2010 the network in the north west of the RoI system becomes unstable if wind is located at Letterkenny and Trillick, without any further reinforcement of the network.

### **3.4 Single – Contingency (N-1) Analysis of Limit of 110 kV Connected Wind Power**

3.4.1 This was done as follows

- (1) A single–contingency (N-1) analysis was done for the Base Cases (i.e. no new wind) provided by the two TSOs. This revealed a number of infringements to the Transmission Planning Criteria.
- (2) The N-1 analysis was then repeated for the maximum limit of 110 kV connected Wind Power – as presented in Tables 3.3.1, 3.3.2 and 3.3.3, respectively. A number of new infringements were observed which were additional to the infringements observed in (1) above.

Infringements to the Transmission Planning Criteria were of two types:

- (1) Overloading of 110/38 kV transformers.

These infringements were disregarded because they were originated by an increase in the load demand without the corresponding increase in installed power transformer capacity. This would be the case regardless of whether the power flowing through them from the 110 kV system was generated conventionally or by wind.

- (2) Infringements in the Transmission system itself.

These were examined individually. In every case, removal of the windpower input adjacent to the infringements was sufficient to eliminate them.

However, it was recognised that simple N-1 analysis like that described above does not fully evaluate the risk incurred by single events. The analysis therefore was extended to include two further classes of single events, which have multiple consequences – as follows: -

- (1) Simultaneous failure of both circuits on double–circuit towers.
- (2) 220 kV busbar faults in High-Voltage substations, which take out two sections of busbar. The best example of such a fault would be an insulation failure in a coupler circuit breaker.

This extended analysis was done first for the Base Case. It revealed a number of infringements to the Transmission Planning Criteria.

This analysis was repeated using the limit of 110 kV Connected Wind Power (Tables 3.3.1, 3.3.2 and 3.3.3, respectively). It was found that removing adjacent wind power inputs could eliminate all the additional infringements.

### **3.5 Wind Power Inputs at Higher Voltages (220 kV and 275 kV)**

3.5.1 It is also necessary to consider the implications of connecting large blocks of windpower directly at higher voltages (220 kV, and 275 kV) for two reasons:

- (1) Proposals for connections of very large blocks of wind power already have been made, and,
- (2) Two of the largest concentrations of potential wind power are very close to existing 220 kV or 275 kV Substations.

However it must be recognised that, because the upper limit of connected wind power is imposed by available conventional generation considerations, any connections of wind power at 220 kV or 275 kV will eliminate the opportunity to connect a corresponding amount of windpower at 110 kV (or, indeed, lower voltages).

3.5.2 The analysis was done in two stages:

- (1) In stage one, connections were made to 220 kV and 275 kV substations where it was known that large-scale connections were proposed. These were

<b>Windpower Source</b>	<b>Substation Name</b>	<b>Substation Voltage</b>	<b>Maximum MW</b>
Arklow Bank	Arklow	220 kV	400
Kish Bank	Carrickmines	220 kV	400
Oweninny	Flagford	220 kV	400
Tunes Plateau	Coolkeeragh	275 kV	250

**Table 3.4 Locations of Large Scale Connections**

Values of 400 MW were chosen for Arklow, Carrickmines and Flagford because the system in 2005 without wind power (Base Case) is expected to be able to withstand an abrupt loss of 400 MW (e.g. the Moyle Interconnector). 220 kV busbar fault in any of those stations would cause the total loss of the connected windpower. A value of 250 MW was chosen for Coolkeeragh because this is the proposed size of the Tunes Plateau development.

- (2) In stage two, an additional connection was made at 220kV.

<b>Windpower Source</b>	<b>Substation Name</b>	<b>Connection Voltage</b>
West Wicklow	Dunstown	220 kV

**Table 3.5 Assumed Connection to Optimally-Sited High-Voltage Substation**

For both stages, corresponding reductions were made in the 110 kV inputs of Tables 3.3.1, 3.3.2 and 3.3.3, respectively.

3.5.3 Analysis results of Stage 1 showed that:

- (1) The wind power inputs of Table 3.4 could be accommodated without difficulty on an intact system.
- (2) The extended N-1 analysis indicated that, although the presence of wind power led to more infringements than existed in the Base Case, all of these infringements disappeared when appropriate wind power inputs were disconnected.

3.5.4 Analysis results of Stage 2 showed that:

- (1) 400 MW of wind power could be accepted at Dunstown without difficulty.

## **4. Discussion of Results**

### **4.1 Commercial Limit of Wind Power**

- 4.1.1 The maximum acceptable wind power capacity is estimated in Section 3 above to be about 4000 MW for the island of Ireland (3900 MW in 2005, 4085 MW in 2007 and 3915 MW in 2010), without significant reinforcement required for the 110 kV Transmission network. However, it would not be commercially practical to install all this capacity. This is so because the opportunity to connect the full amount would exist for only a few hours in each year, around the time of peak system demand.
- 4.1.2 The above maximum limit of installed wind-power capacity of 4000 MW assumes that the wind-farm developers agree to be disconnected from the network (or to reduce output) automatically and immediately in the event of a critical system contingency, as requested by the TSO. This is known as ‘Remedial Action Scheme’ (RAS).

Implementation of RAS involves an intertripping scheme at the wind-farm connection point with each of the remote substations. Failure will cause infringements of the Transmission Planning Criteria (i.e. should one of the identified contingencies occur, a command signal must be sent to the wind-farm to be disconnected from the system).

Successful operation of RAS requires the installation of a fast, reliable and secure communication channel between the wind-farm and each of the identified substations. Suggested options for the communication channels are “leased digital line” and “frame relay”. Both options involve “one-off” and “recurring” costs. Estimated budget for a communication link using any of the above technologies is around €20k over 10 years (i.e. €2k per year for 10 years, decreasing thereafter), based on an average length of leased line of 25 km or a distance of 5 km to the nearest frame relay node. Four communications links would be required per wind farm.

It must be understood that this ‘Remedial Action Scheme’ (RAS) will only be necessary under certain heavy load conditions or planned maintenance, but the system must be ready and available to be activated as soon as the TSOs require it.

- 4.1.3 Additional preliminary studies indicated that, if the maximum limit of installed capacity is reduced from 4000 MW to 3300 MW (assuming all the wind-power installed capacity connected to the 110 kV system), the infringements to the planning criteria during the N-1 contingency disappear without the need to reduce or disconnect any wind-power output. Clearly there will be other, more complex contingencies that could apply, and which the TSOs would define for any particular project, but the need for RAS is likely to be much less below this level of approximately 3300 MW.
- 4.1.4 The dominant constraining factor was found to be the thermal limits of elements of the existing system (see 2.1). No significant geographic trend was found for this conclusion. Voltage control problems were not found to be a major issue, and in fact existing voltage control problems were eliminated when wind was added to the system.

- 4.1.5 The system demand varies over daily and annual load cycles between a minimum value at night in summer, and a maximum value during certain working hours in winter. Minimum connected conventional generation is reduced proportionally, which limits the amount of wind power that can be connected to the system during that period. Tables 4.1.1, 4.1.2 and 4.1.3 depict the maximum wind power that can be accepted at 110 kV by the intact system in the three target years at the minimum of system load conditions. It must be understood that this minimum load condition, and consequent restriction in wind power output, occurs only during a limited number of hours a year.

<b>System</b>	<b>Conventional Generation</b>	<b>System Demand (Wtotal)</b>	<b>110 kV Limit of Acceptable Wind Power</b>
<b>RoI</b>	850	1640	790
<b>NI</b>	530	560	30
<b>Total</b>	1380	2200	820

**Table 4.1.1 Maximum Acceptable Wind Power at Time of System Minimum Demand in 2005**

<b>System</b>	<b>Conventional Generation</b>	<b>System Demand (Wtotal)</b>	<b>110 kV Limit of Acceptable Wind Power</b>
<b>RoI</b>	690	1730	1040
<b>NI</b>	525	585	60
<b>Total</b>	1215	2315	1100

**Table 4.1.2 Maximum Acceptable Wind Power at Time of System Minimum Demand in 2007**

<b>System</b>	<b>Conventional Generation</b>	<b>System Demand (Wtotal)</b>	<b>110 kV Limit of Acceptable Wind Power</b>
<b>RoI</b>	740	1880	1140
<b>NI</b>	520	600	80
<b>Total</b>	1260	2480	1220

**Table 4.1.3 Maximum Acceptable Wind Power at Time of System Minimum Demand in 2010**



- 4.1.6 Tables 4.1.1, 4.1.2 and 4.1.3 indicate that, if about 1000 MW of wind power were installed in the island of Ireland (820 MW in 2005, 1100 MW in 2007 or 1220 MW in 2010), this capacity could be connected to the system, delivering energy, at any time over the year. However, it also shows that, for any installed wind power capacity in excess of this, the opportunity to deliver energy to the system would be progressively less, until, for the last MW of wind power, the opportunity to deliver energy to the system would be zero. This means that the principle of “Diminishing Returns” would apply to any installation of wind power which would increase the total installed amount above about 1000 MW.

## **4.2 Generation Limit of Acceptable Wind Power**

- 4.2.1 This limit, as determined in Subsection 3.1, assumed that because wind power could disappear completely from the system, no conventional generation could be disconnected. This is a conservative assumption. It could be relaxed if wind forecasting techniques could provide reliable warning of changes in wind speed far enough in advance to allow disconnected generation to be started and brought to full power in time. In this event some generators could be disconnected, so reducing their fuel consumptions from their minimum-output values to zero, and allowing corresponding increases in wind power penetration.

## **4.3 Assumption 1.5 – Wind Generator Characteristics**

- 4.3.1 It is important to recognise that the very high values of acceptable wind power penetration which are presented in this report could be achieved only if the performance of wind generators were comparable to that of existing designs of conventional generators in terms of reactive power capabilities. This is not at present the case. However there would seem to be no reason why the necessary improvements in performance could not be achieved by applying well proven technology.

## APPENDIX 4

### Fluctuation of Wind Farm Power Output and Incidence of Calms

#### 1. INTRODUCTION

GH obtained SCADA data for turbine power output from the following Scottish Power (SP) wind farms in the UK:

- Hare Hill: 16 x 650 kW, pitch-regulated, limited-range variable speed (Optislip)
- Dunlaw: 26 x 660 kW, pitch-regulated, limited-range variable speed (Optislip)
- Hagshaw Hill: 26 x 600 kW, stall-regulated, fixed speed (two speeds)
- P and L (Penrhyddlan and Llidiartywaun): 103 x 300 kW, fixed speed pitch-regulated

These data were supplied at 10-minute resolution and were used to investigate the fluctuation of power output from the wind farms at sub-hour resolution. Previous work [1] produced similar analysis based on hourly mean wind speeds from five sites across Ireland. The work reported here therefore complements this previous work by analysing data that is:

- Of higher resolution.
- From actual operating wind farms.

#### 2. ANALYTICAL METHOD

The datasets were analysed at the following resolutions (“averaging periods”):

- 10 minutes
- 20 minutes
- 30 minutes
- 60 minutes

... and for the following time step intervals:

- 1 time step
- 2 time steps
- 3 time steps
- 4 time steps
- 5 time steps
- 6 time steps
- 12 time steps
- 24 time steps

An interval of 6 time steps means that the power generated at time  $T$  is compared with the power generated at time  $T+6$ . The difference is normalised to percent of rated power. A full time history of such differences is then created:

$$\text{Diff} = 100 * (P(T+6) - P(T)) / P_{\text{rated}}$$

A 6-time step interval at 10-minute resolution is equivalent to 1 hour, while at 30-minute resolution it is equivalent to 3 hours.

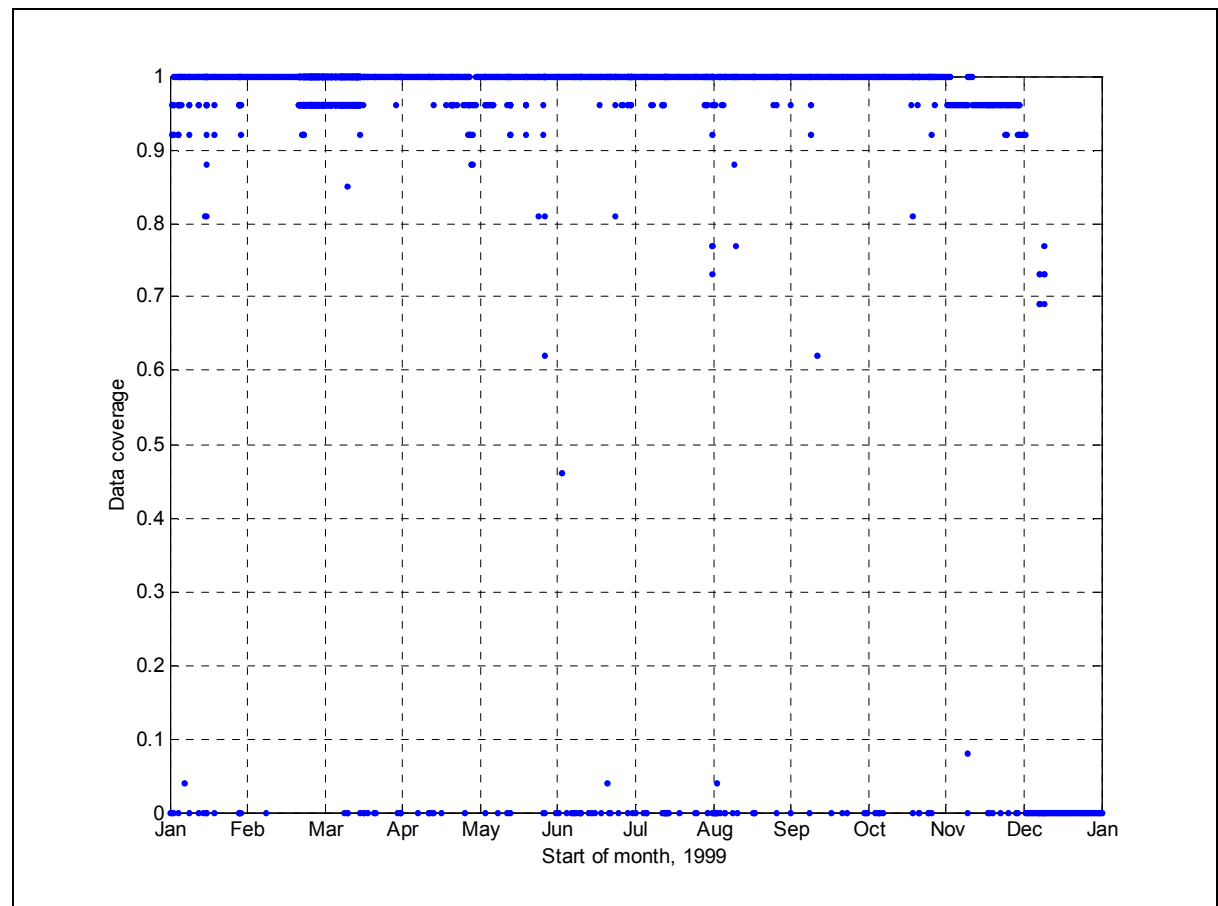
The SCADA data were not 100 % complete. The power output is available on a per turbine basis, with wind farm output being a summation of all turbine outputs. If there was not full coverage of turbine records (e.g. if only 15 out of the 26 turbines at Hagshaw Hill posted records) then the total from the available turbines was scaled appropriately (i.e. by 26/15 in this case) to provide an estimate of what the full wind farm output would have been. Note that this was only done for missing records, not for records indicating zero output. Any instances where there were missing records for the entire wind farm were ignored in the analysis.

To accommodate comparison between analysis of data periods of differing lengths, all results are presented as percentages of total available data.

### 3. THE RESULTS

#### *Single wind farms*

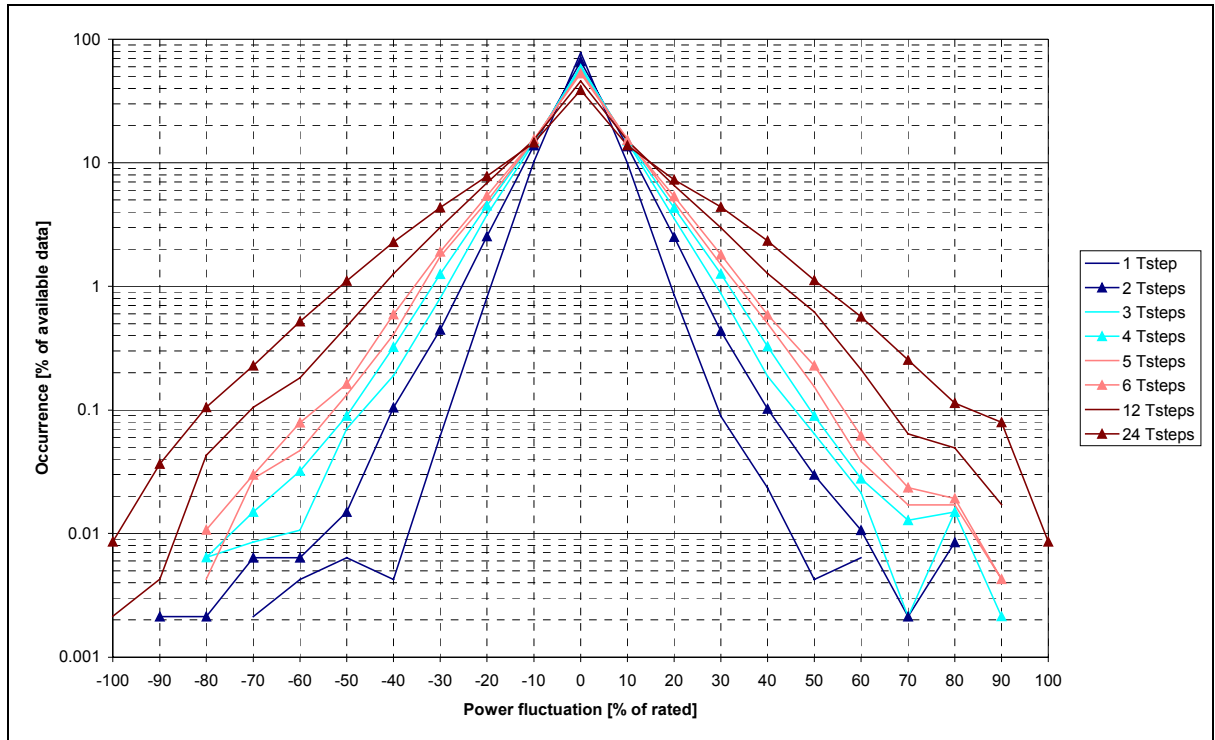
One full year (1999) of Hagshaw Hill data was analysed and is presented below. Data coverage at 10-minute resolution is shown in Figure 3.1.



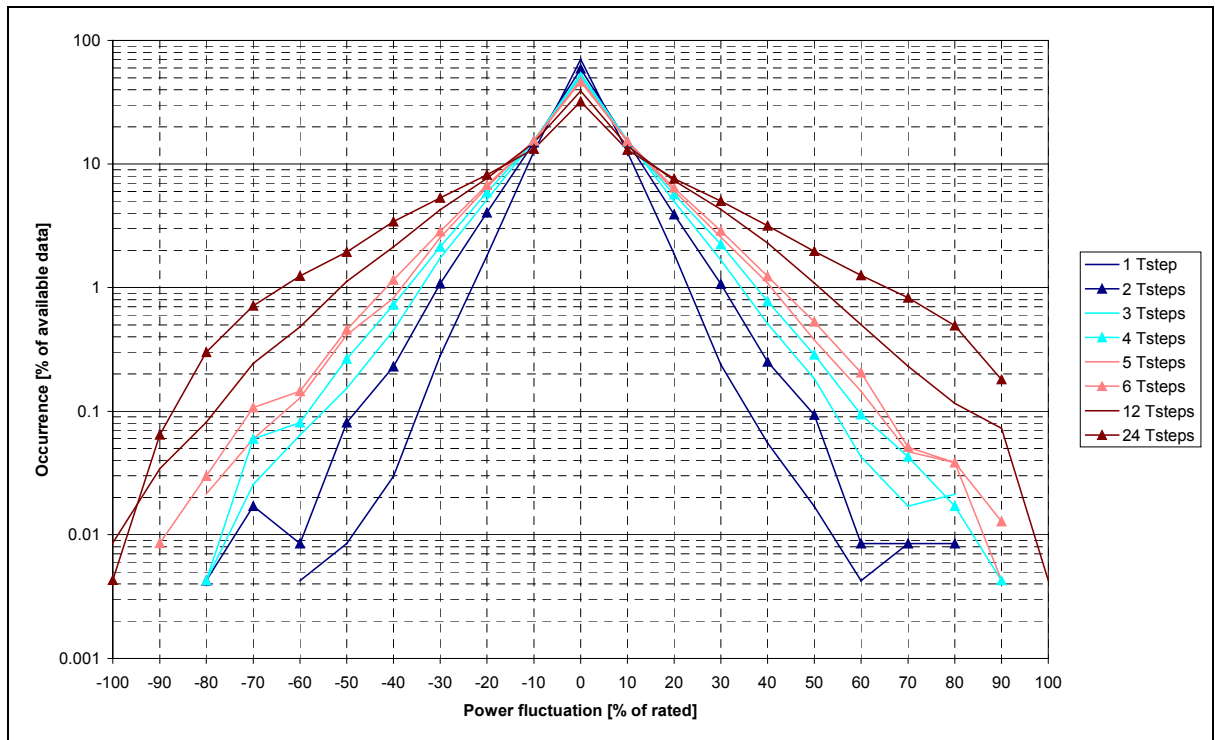
**Figure 3.1 Data coverage for Hagshaw Hill, 1999, 10 minute resolution**

The results of the analysis are presented as:

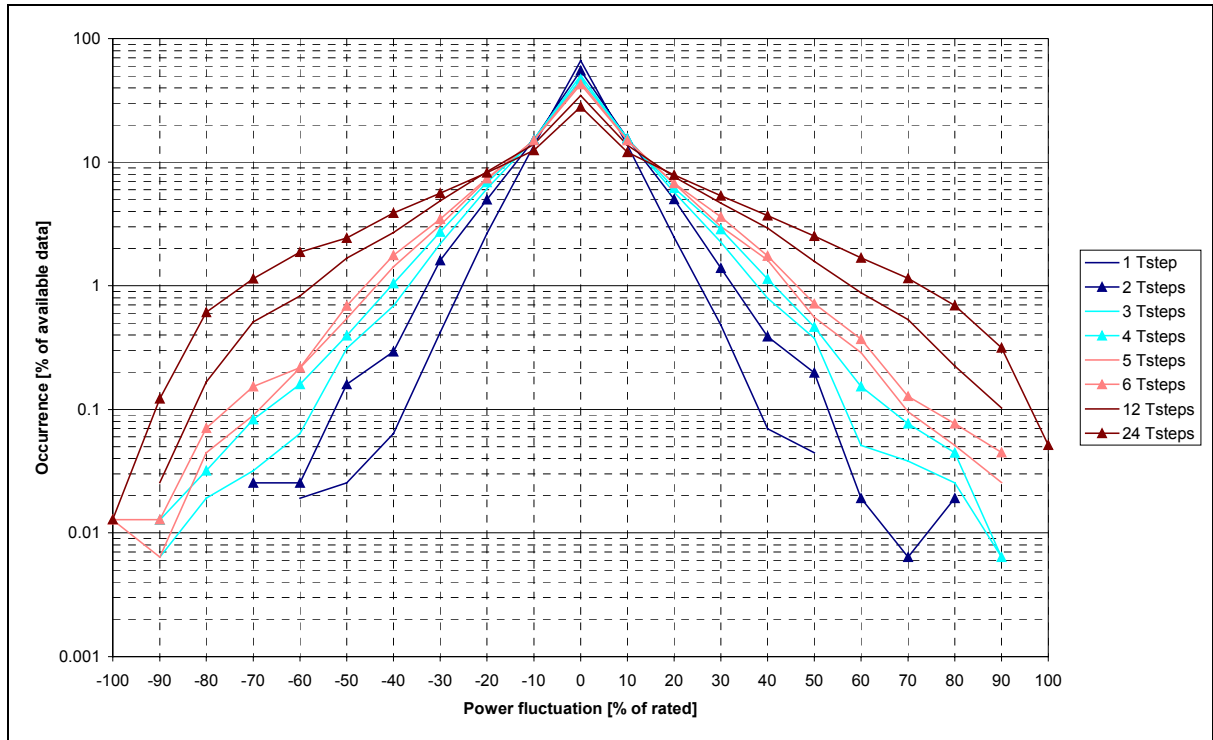
- X axis: magnitude of change (“fluctuation”) in output power over N time steps (processed by the method of bins, bin width 10%, centred on 0%);
- Y-axis: frequency of occurrence of power fluctuation, presented as percentage of total available data.



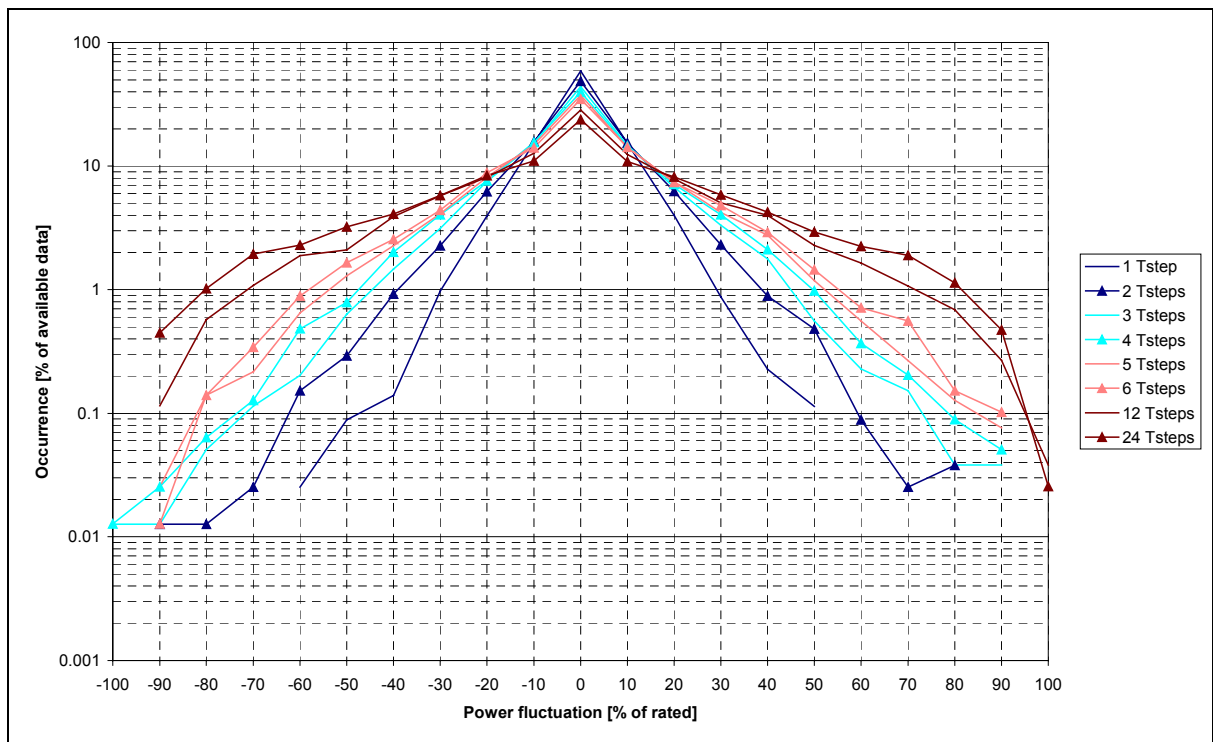
**Figure 3.2** Hagshaw Hill, 1999, averaging period = 10 mins



**Figure 3.3** Hagshaw Hill, 1999, averaging period = 20 mins

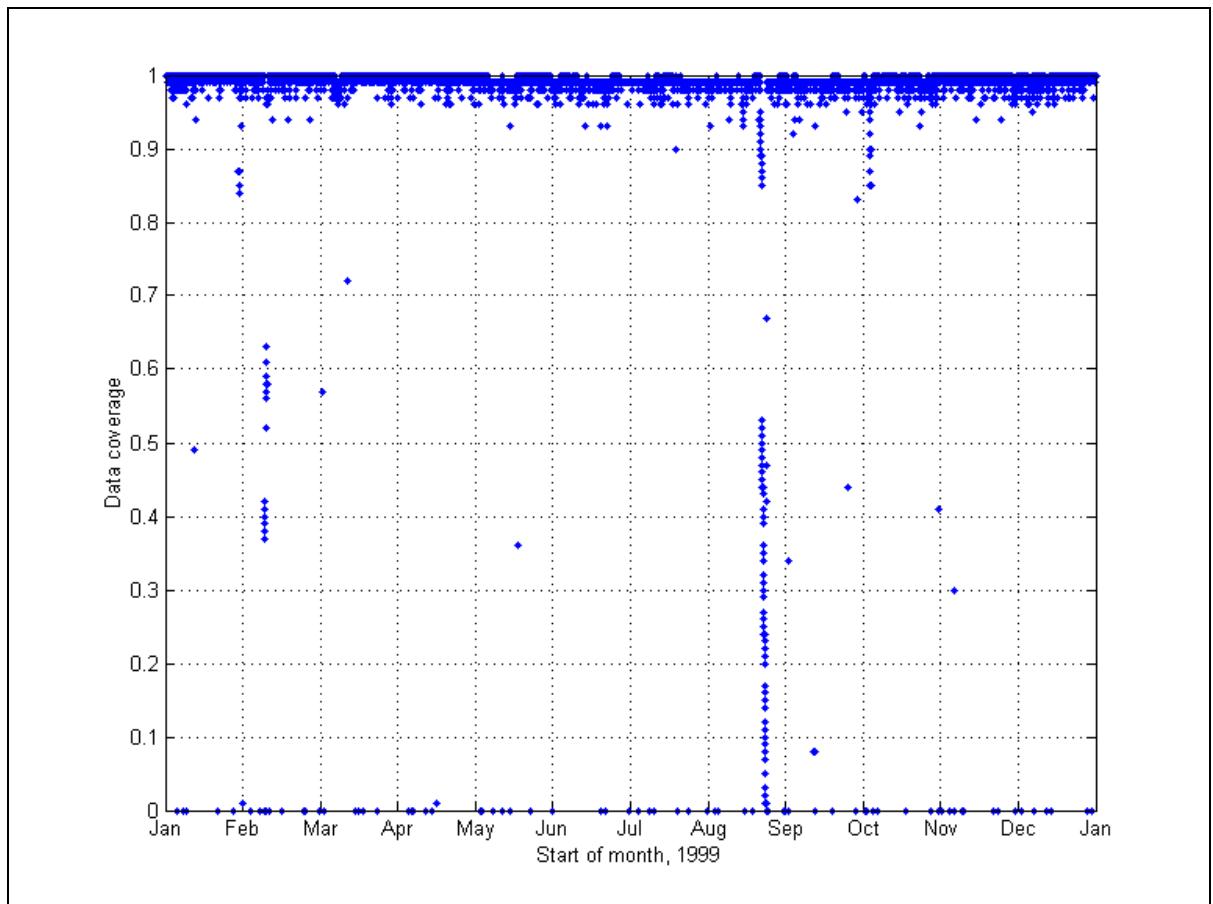


**Figure 3.4 Hagshaw Hill, 1999, averaging period = 30 mins**

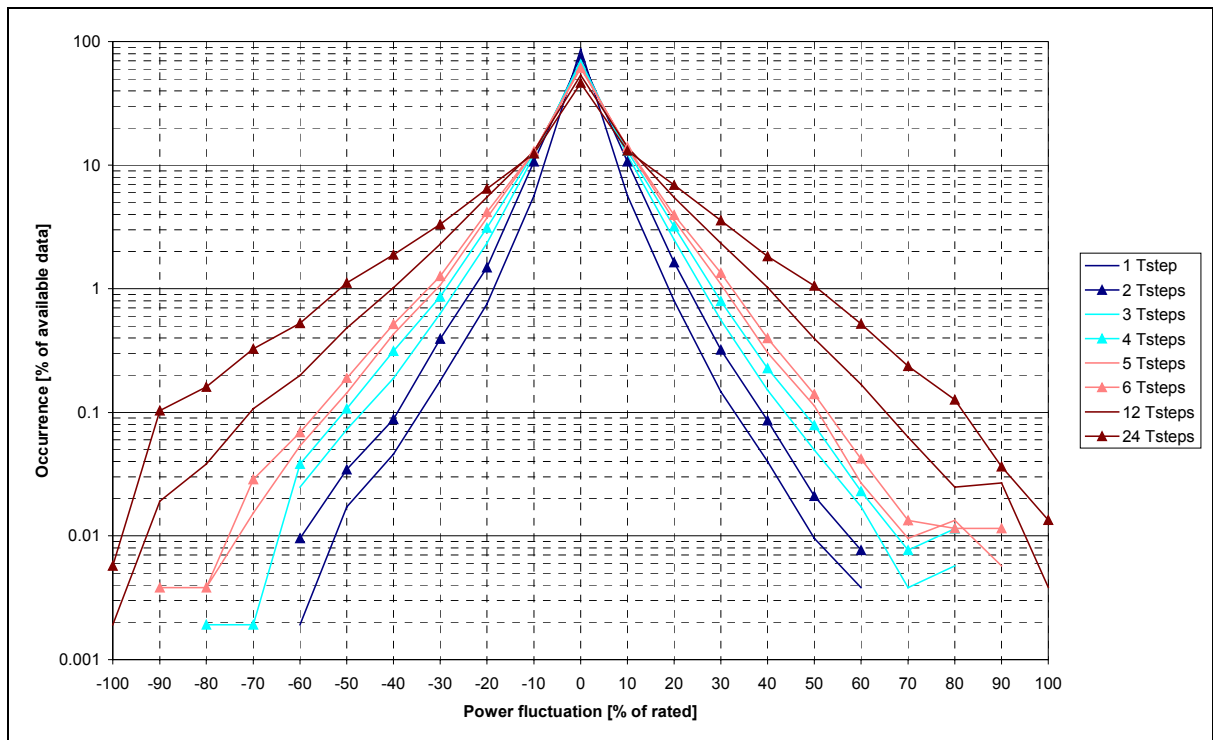


**Figure 3.5 Hagshaw Hill, 1999, averaging period = 1 hour**

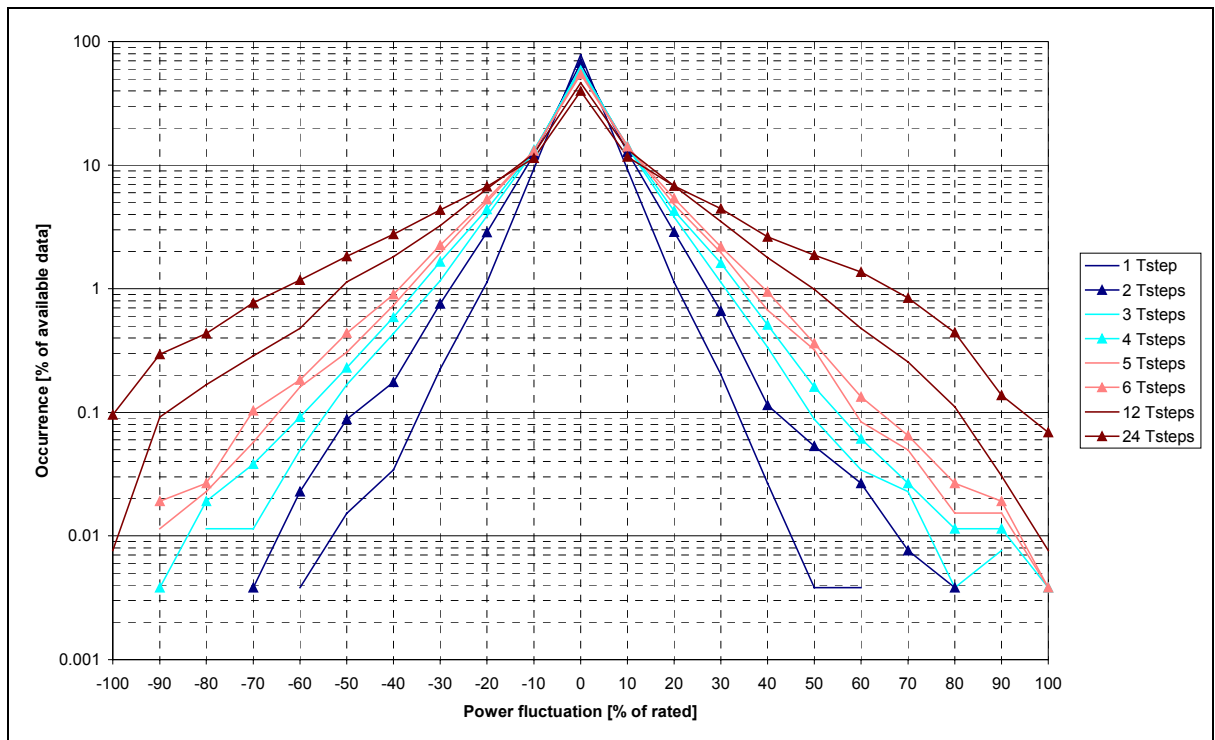
One full year (2000) of P&L data was analysed and is presented below. The data coverage is shown in Figure 3.6.



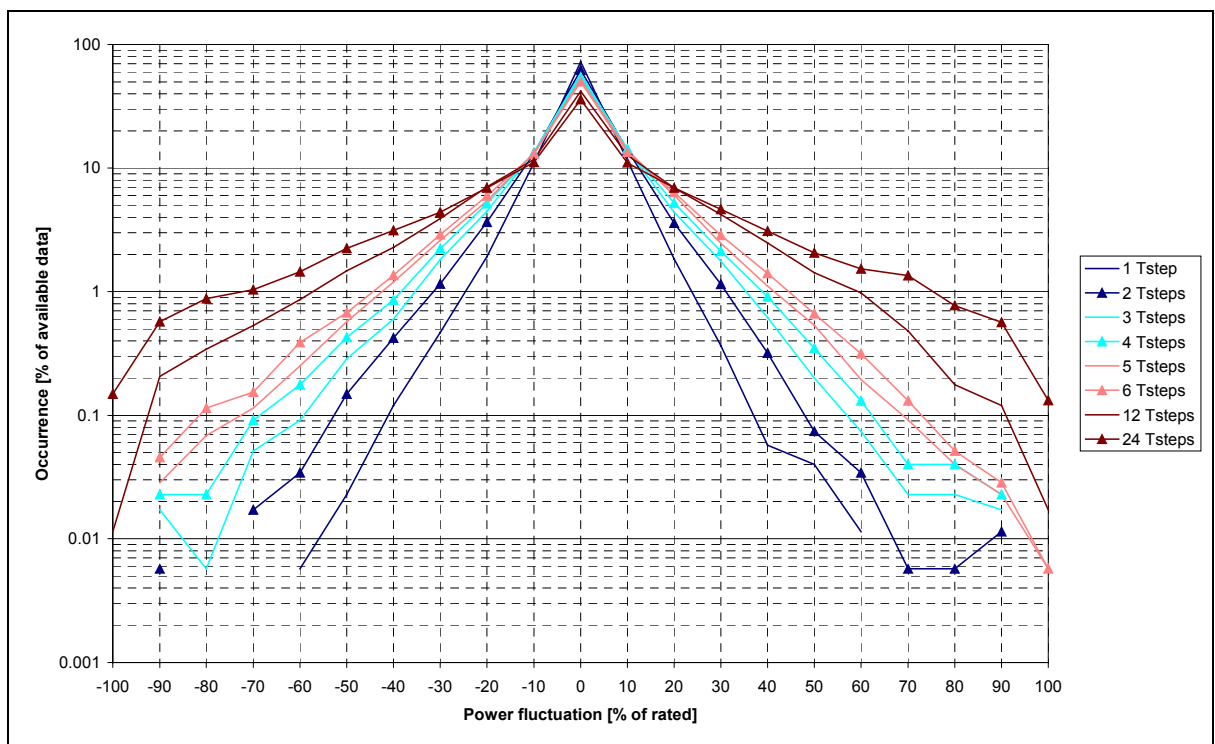
**Figure 3.6** Data coverage for P & L, 2000, 10 minute resolution



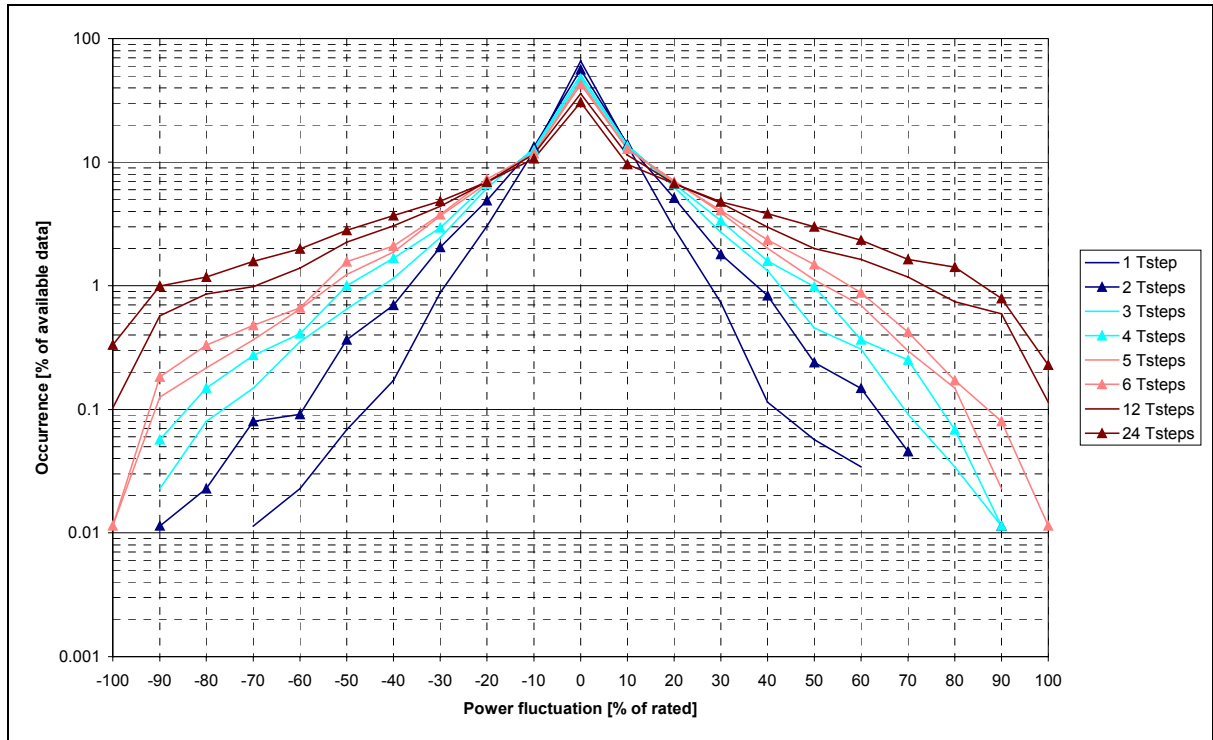
**Figure 3.7** P&L, 2000, averaging period = 10 mins



**Figure 3.8** P & L, 2000, averaging period = 20 mins



**Figure 3.9** P & L, 2000, averaging period = 30 mins



**Figure 3.10 P & L, 2000, averaging period = 1 hour**

Several points should be noted in the figures above.

#### ***Resolution of data***

From figures 3.2 to 3.5 it can be noted that as the averaging period is increased, the lowest points on the graphs also increase. This is because the lowest points on each graph are each the result of a single event. For figure 3.2, an event is 10 minutes in duration, or approximately 0.002% of the dataset. For figure 3.5, an event is 1 hour in duration, or approximately 0.012% of the dataset. It is important to realise that the lowest points on each line, which also of course show the most extreme fluctuations, are functions of the length of the dataset. Longer datasets can be expected to show more extreme fluctuations.

#### ***Effect of high resolution data***

The results for the high-resolution data (10 minute averaging period) show greater fluctuations than the 'slower' data (1 hour averaging period). This is as expected, and indicates that if a system operator is interested in the fluctuations from a single wind farm at resolutions less than 1 hour, then data with an appropriate sampling rate should be used.

#### ***Comparison of wind farms***

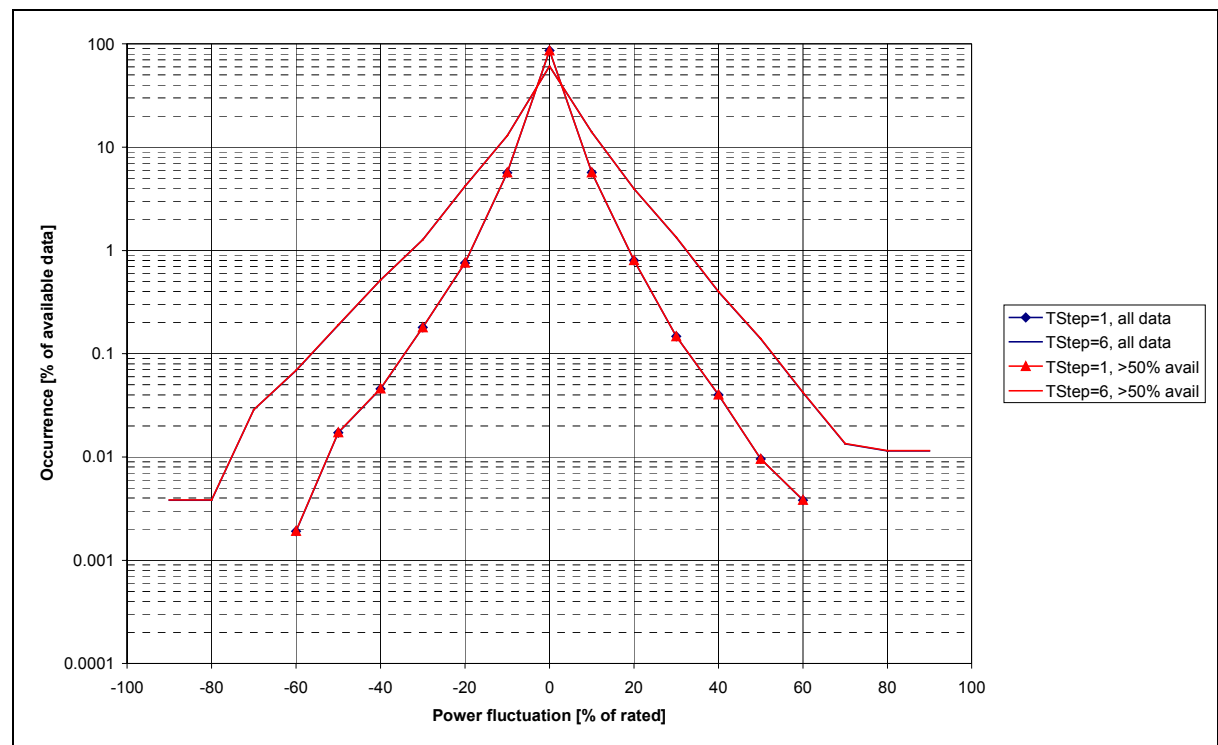
The results from the two wind farms are remarkably similar. Without further data it is not possible to identify the sources of the differences, and in practice the differences are small and unlikely to be important from a system operator's point of view.

#### ***Effect of missing records***

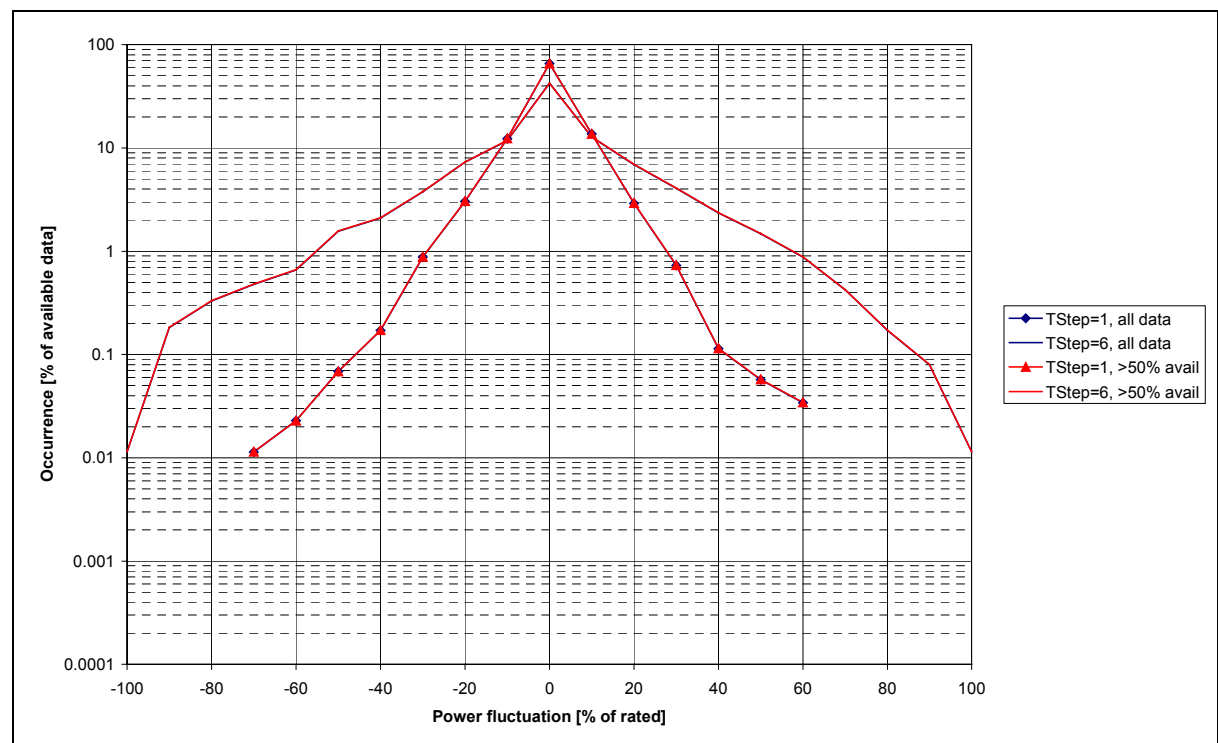
As noted in Section 2, missing records in any timestep are dealt with by scaling the output of the turbines for which there are records. This has the disadvantage that for timesteps where there are few valid records, the resulting calculated power fluctuations may be expected to be larger than in reality. To check the effect of this, the data for P&L 2000 were re-analysed,



omitting any timesteps in which fewer than 50% of the turbines had valid records. The results are virtually identical for all combinations of resolution and interval – see Figure 3.11 and Figure 3.12 below. However, it can be seen from Figure 3.6 above that the number of data points at 50 % coverage or less is fairly small in the first place, so this result is not surprising. There presumably would be more of an observable difference had there been poorer data coverage.



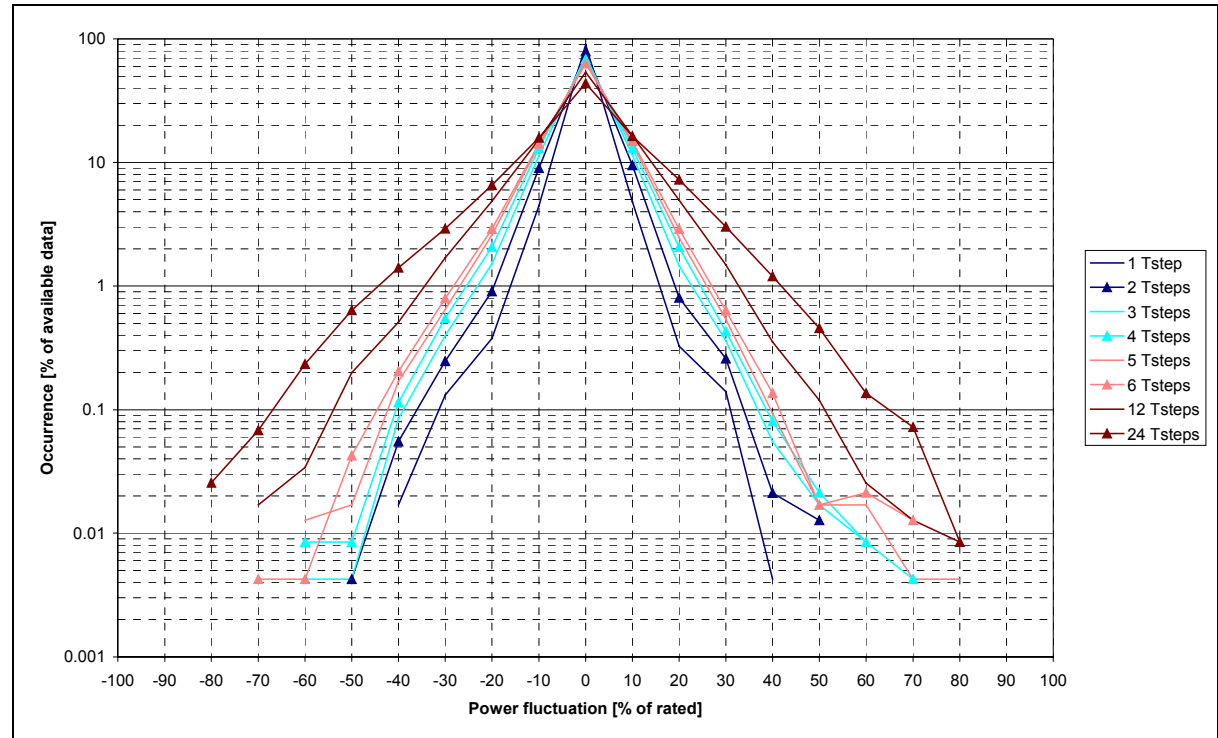
**Figure 3.11** Effect of missing data, 10 min resolution, P&L 2000



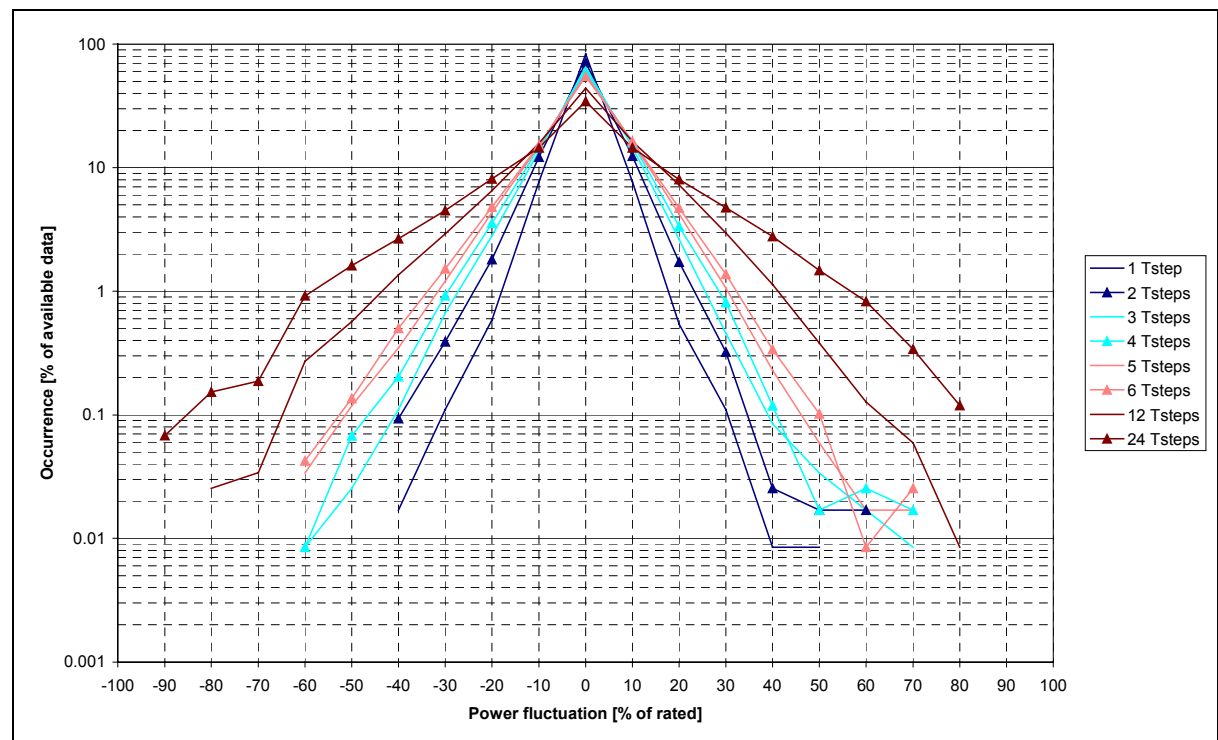
**Figure 3.12** Effect of missing data, 1 hour resolution, P&L 2000

### *Multiple wind farms*

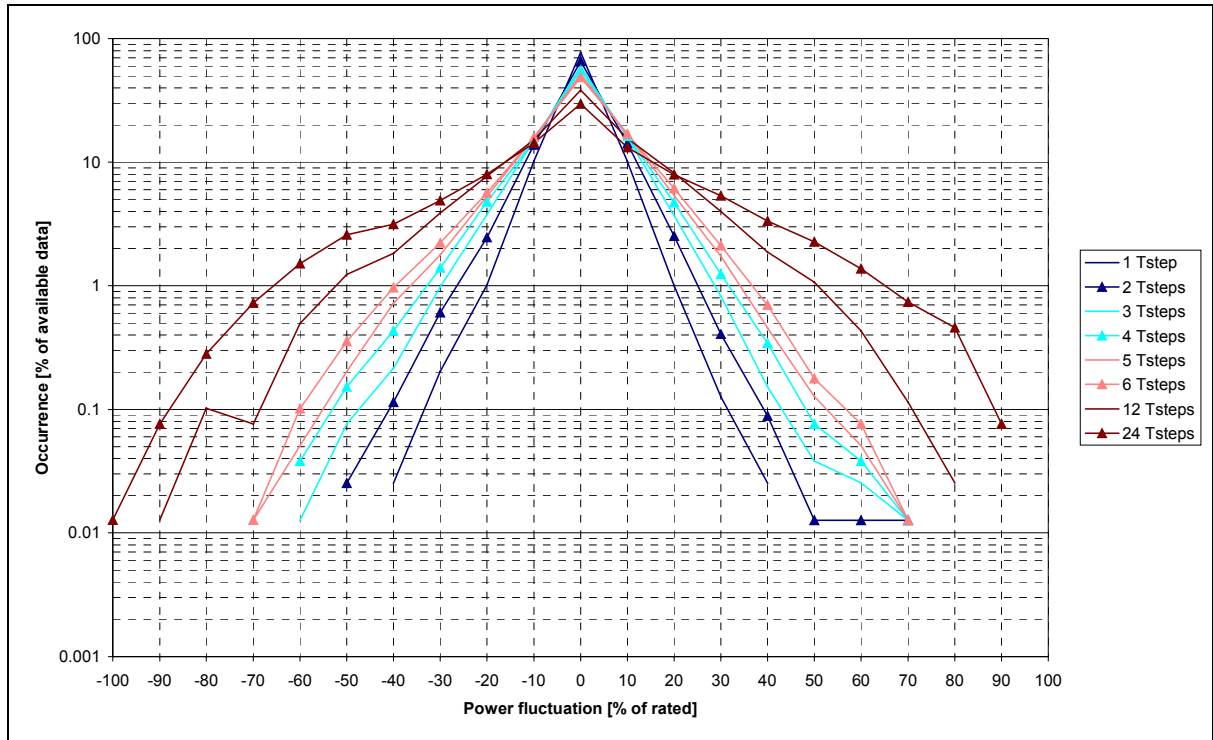
The data from P&L and Hagshaw Hill overlapped for the period 1 Jan to 14 June 2000. An analysis of their combined output is presented below. P&L is approximately 350 km south of Hagshaw Hill.



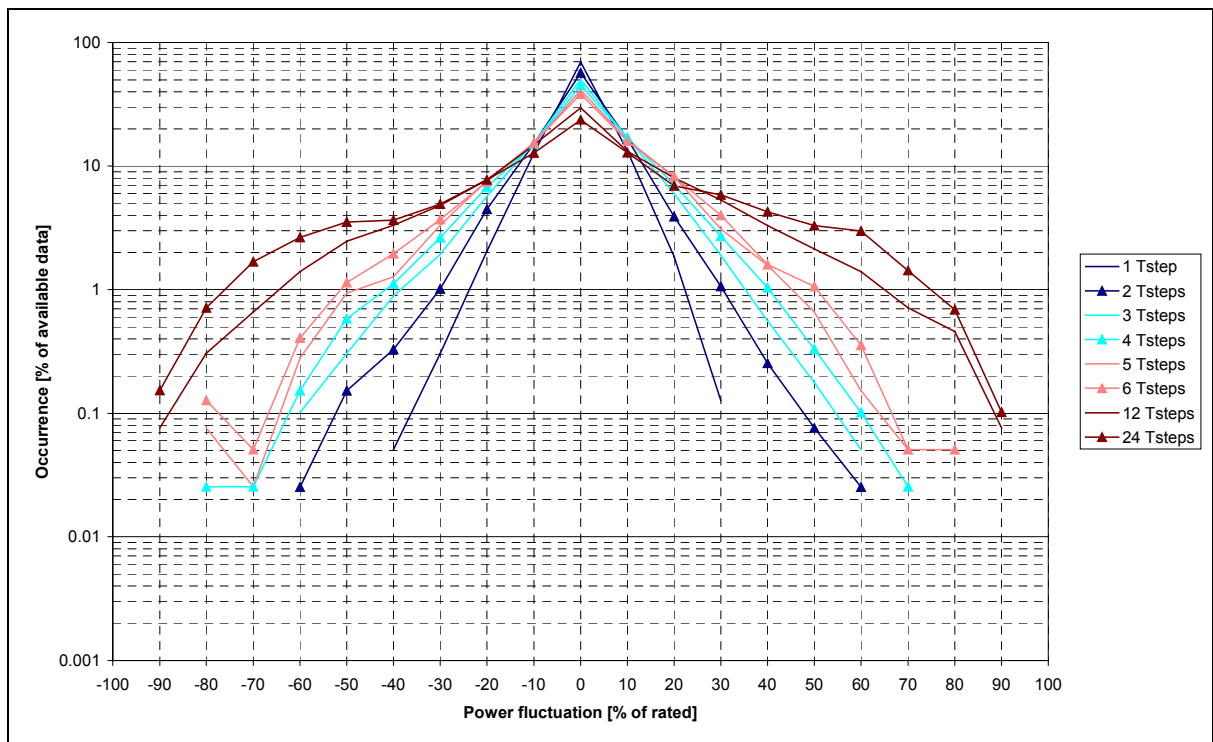
**Figure 3.13** Combination of Hagshaw Hill and P & L, averaging period = 10 mins



**Figure 3.14** Combination of Hagshaw Hill and P & L, averaging period = 20 mins

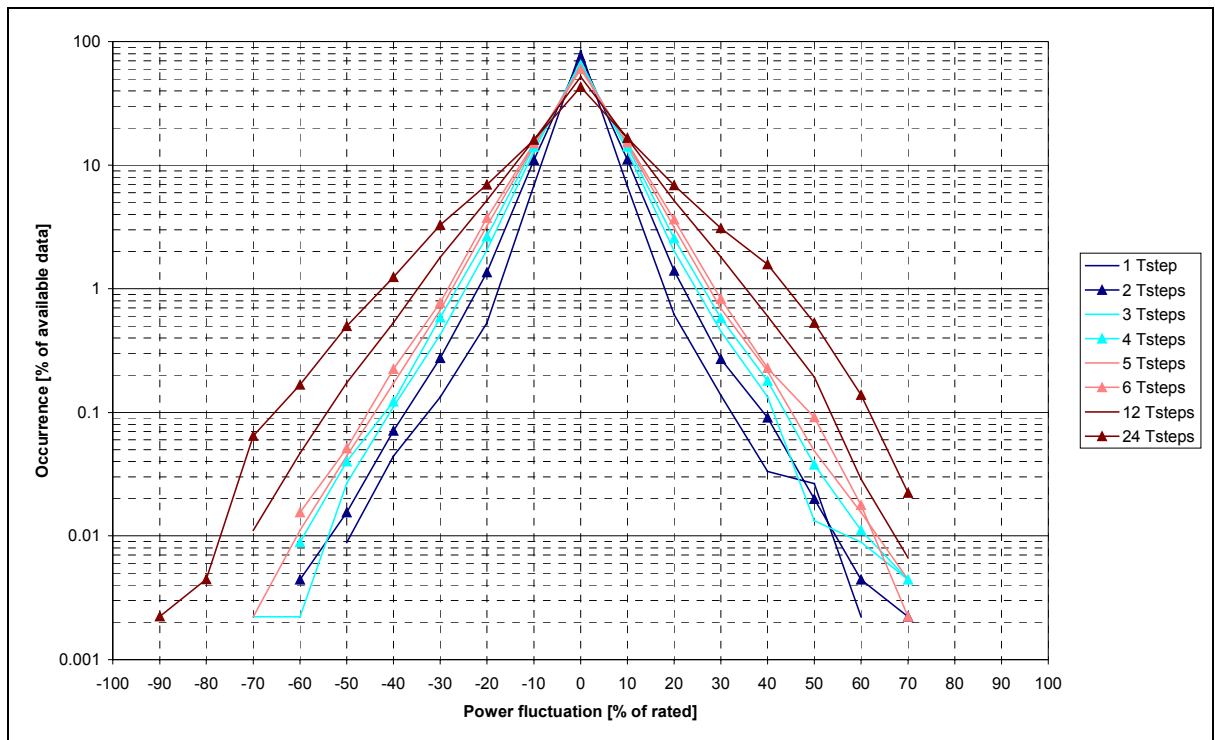


**Figure 3.15** Combination of Hagshaw Hill and P & L, averaging period = 30 mins

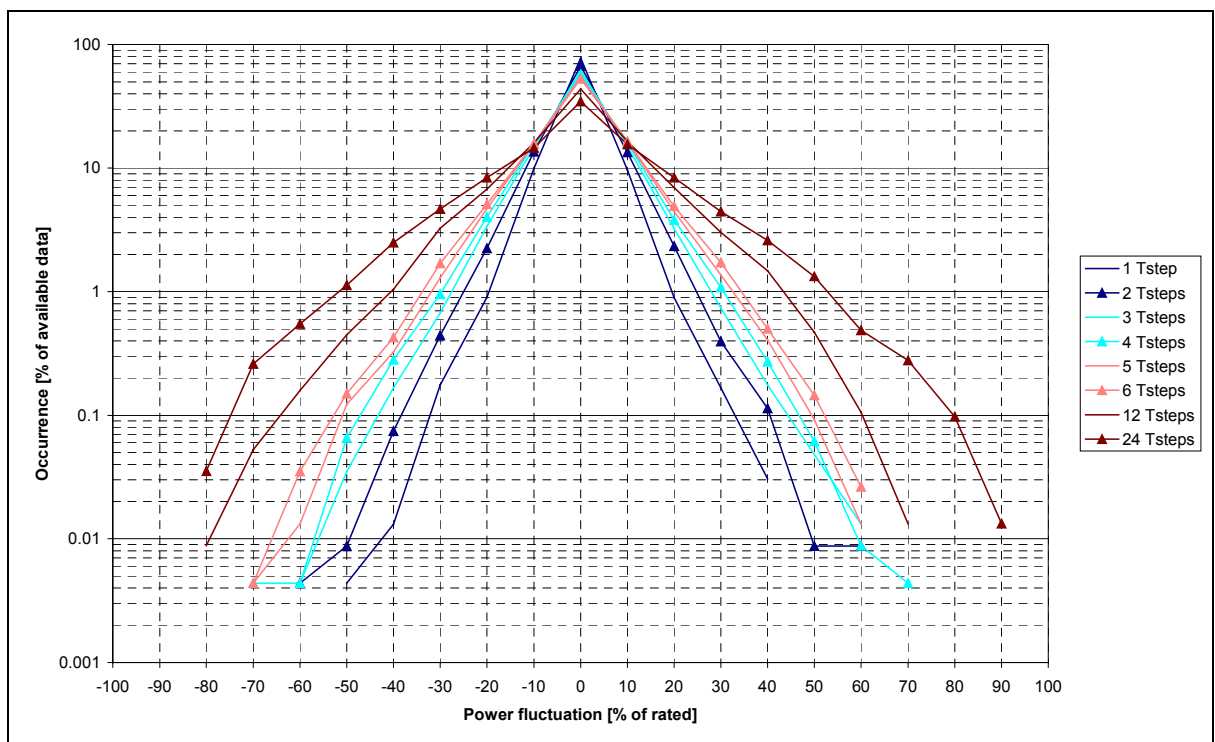


**Figure 3.16** Combination of Hagshaw Hill and P & L, averaging period = 1 hour

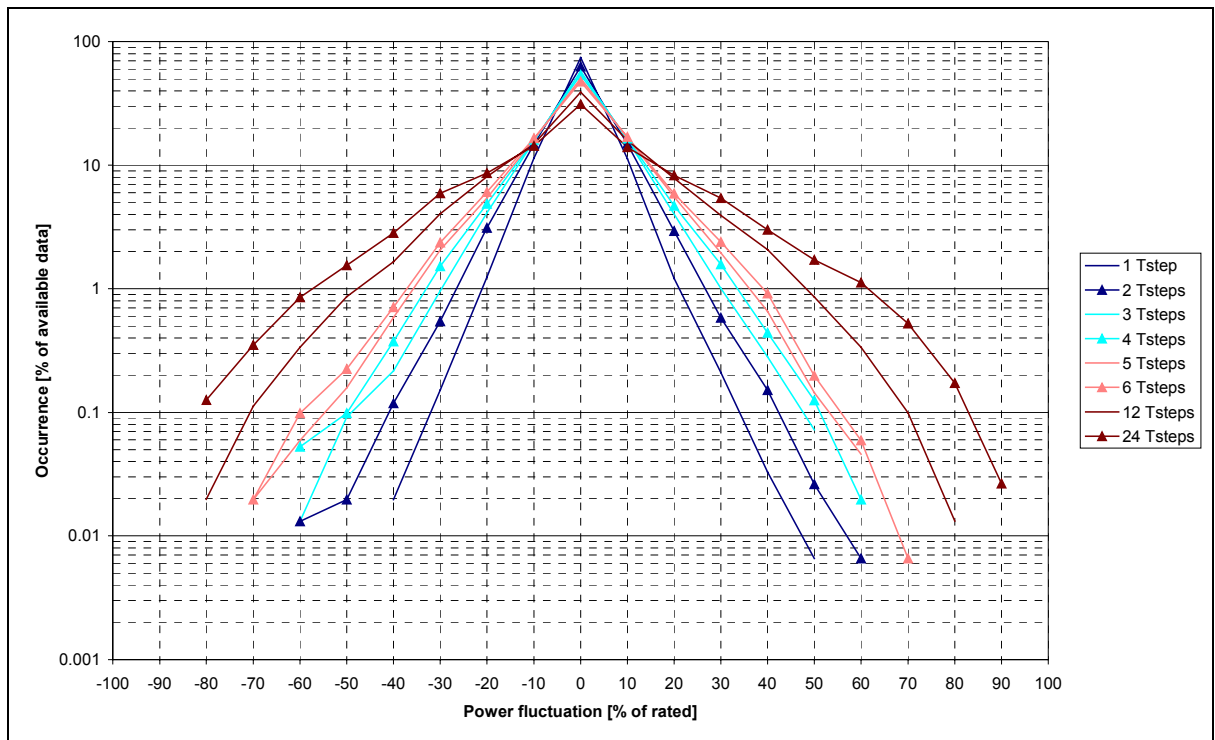
Similarly, the data from Hare Hill and Dunlaw overlapped for the period Nov 2000 to Sep 2001. The analysis for this combination is shown below. Dunlaw is approximately 80 km east-north-east of Hare Hill.



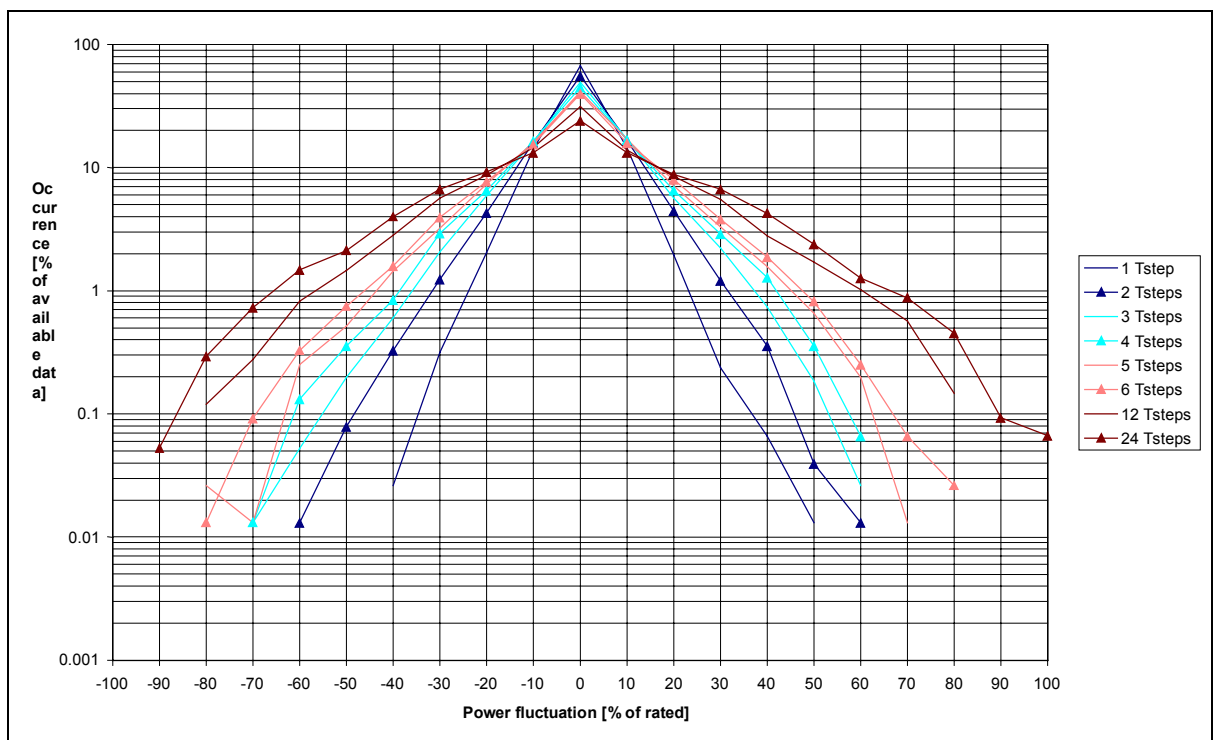
**Figure 3.17** Combination of Hare Hill and Dunlaw, averaging period = 10 mins



**Figure 3.18** Combination of Hare Hill and Dunlaw, averaging period = 20 mins



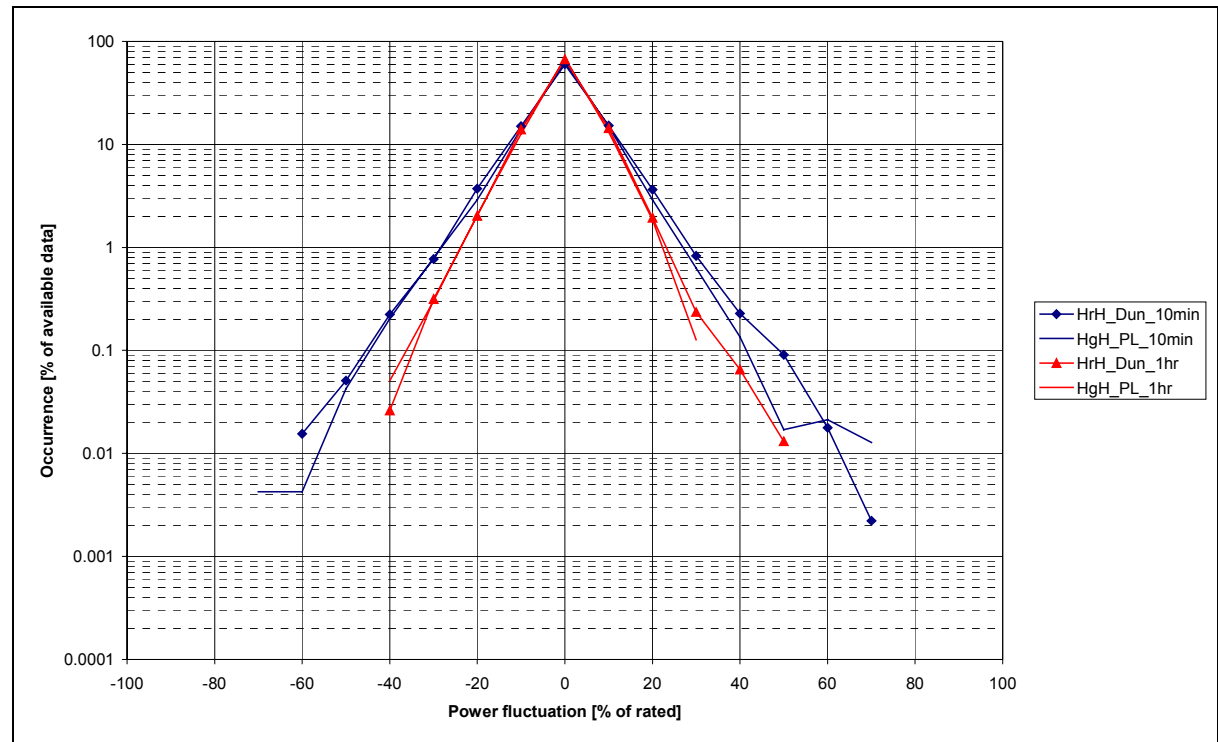
**Figure 3.19** Combination of Hare Hill and Dunlaw, averaging period = 30 mins



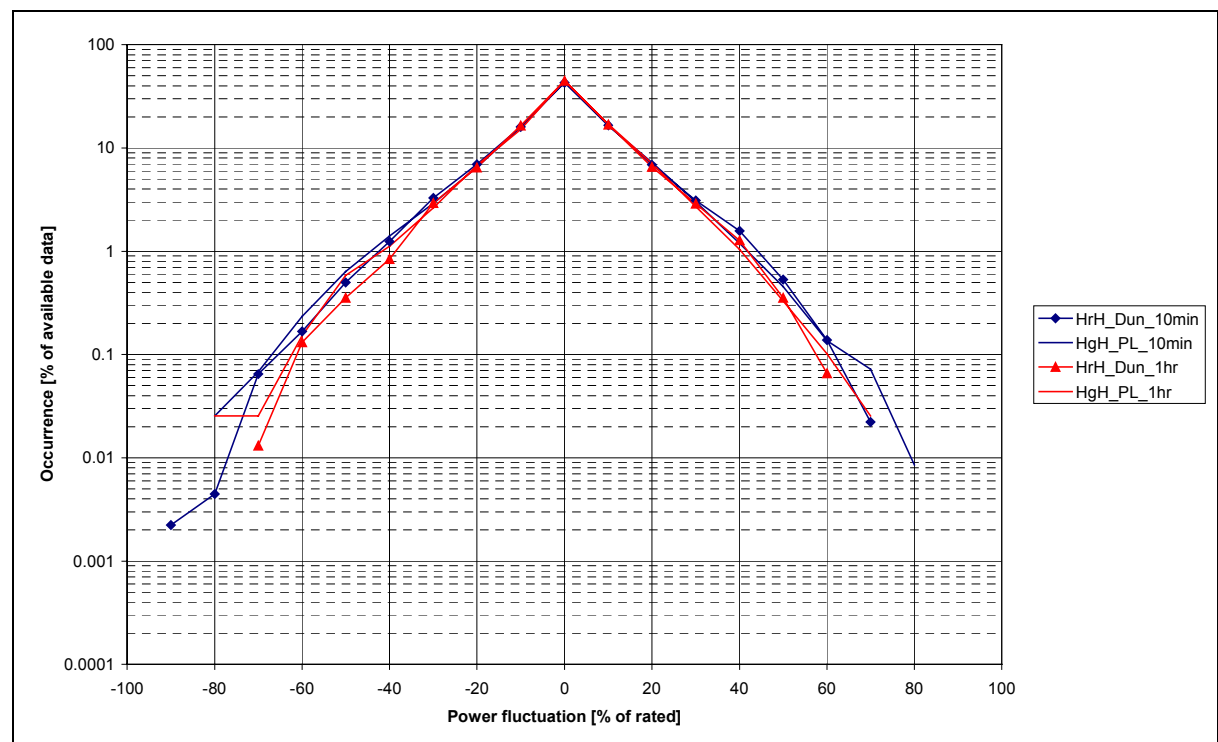
**Figure 3.20** Combination of Hare Hill and Dunlaw, averaging period = 1 hour

### *Effect of high resolution data*

As for Section 3.1, the results for 10 minute averaging periods show more extreme fluctuations than for 1 hour averaging periods, though the difference is reduced. Therefore, if system operators are interested in the behaviour of multiple wind farms at sub-hourly timescales, high-resolution data should be used if available. However, the importance of higher resolution data appears to lessen as the look-ahead time increases – see Figure 3.21 and Figure 3.22 below.



**Figure 3.21** Power fluctuation over 1 hour intervals, comparing 10 minute and 1 hour resolution



**Figure 3.22** Power fluctuation over 4 hour intervals, comparing 10 minute and 1 hour resolution

### ***Comparison of results for multiple wind farms.***

The results for the two pairs of wind farms are remarkably similar, given the different data set lengths and the different geographical separation.

### ***Comparison with Ecofys results***

In order to compare the above results with the previous work published by Ecofys [1], the “number of occurrences in 10 years” was read from Figure 5 (in [1]) by eye, then converted to percentage of time (i.e. from a possible 87660 hours).

The comparisons, using hourly averaging, for power fluctuations at 1, 4 and 12 hour intervals, are shown on the graphs below. Note that the Ecofys results extend to lower occurrence rates and larger fluctuations than for the Scottish Power data, because of the longer time series (10 years compared to less than one year).

It can be seen that the single wind farms are in good agreement with each other, offering noticeably higher percentages of occurrence for any given power fluctuation than the combined cases. The combined cases also agree well with each other, though at 4 and 12 hour intervals the Hare Hill/Dunlaw combination is usually showing lower percentage fluctuations than the Hagshaw Hill/P&L combination.

It can also be seen that the Ecofys figures agree very well with the two combined cases. However, particularly at intervals of 4 and 12 hours, the Ecofys figures appear to show slightly higher percentages of occurrence. This may be due to:

1. Error introduced when reading results from Figure 5 in [1].
2. The fact that the two analyses (i.e. Ecofys work and this work) were based on different time scales, and are from different locations with different topography.
3. The fact that the combined cases in this study use real wind farm data, whereas the Ecofys study was based on wind speed data converted to simulated wind farm output. When looked at in detail, it is clear that there are many instances where some turbines are shut down (presumably for maintenance) while others are generating. This will tend to reduce the likely power fluctuation at any given time. This also agrees with a similar conjecture put forward in Section 4 of [1], where it is thought that the results (from [1]) were conservative in comparison to a similar study made from real wind farm output data.

However, given the differences in the data, the similarity is remarkable. The consequences of this are:

- The results for hourly averaging periods can be used with some confidence by system operators, certainly in northern Europe, without concerns over differences in geography or topography.
- The results for faster averaging periods, shown in Section 3.2, can also be used with some confidence in locations other than the UK. There is only limited analysis of sub-hourly data available elsewhere [2].
- There is no evidence that power fluctuations over 4 or 12 hours from five wind farms combined (as in the Ecofys results) are any smaller than for two combined wind farms. It is only at the short timescales (one hour and, presumably, less) that the most extreme fluctuations from five wind farms combined are smaller than for two wind farms combined.

### ***Worst-case power fluctuation for planning purposes***

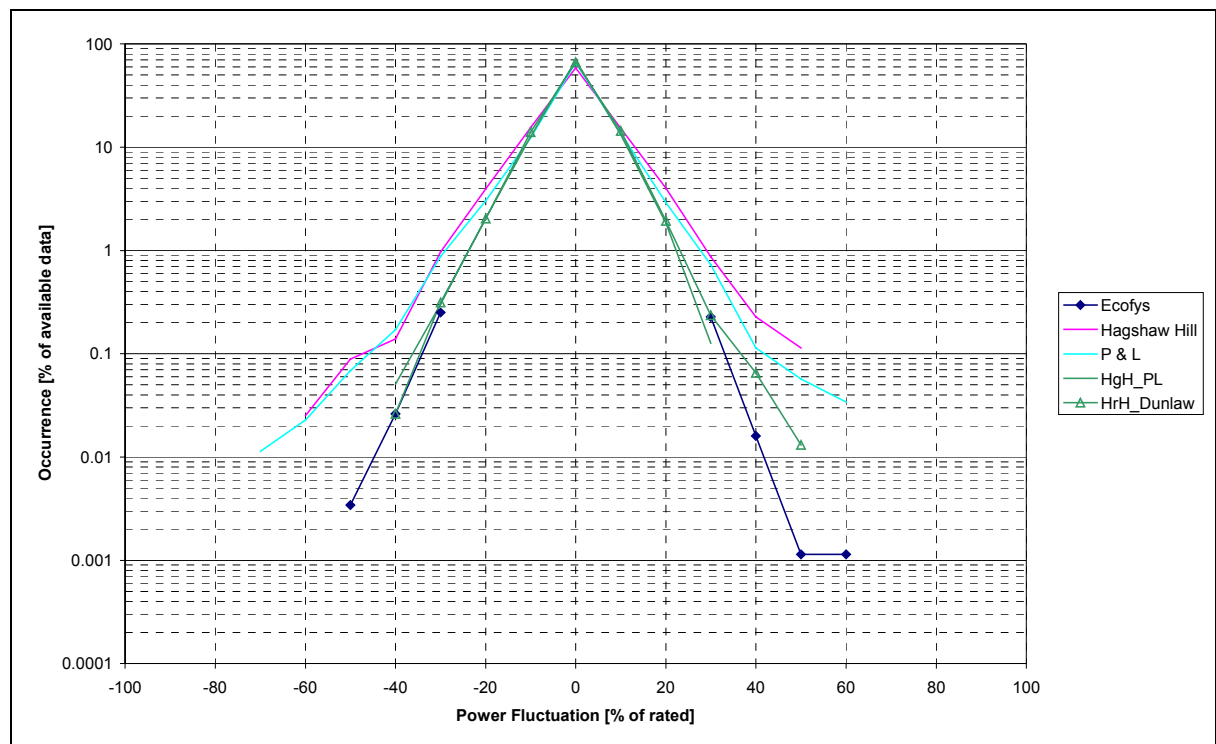
Assuming that the criterion for an acceptable level of risk is taken as one event in 100 years (a figure arbitrarily proposed by GH), then for hourly data as displayed in Figures 3.23 to 3.25 this equates to an occurrence rate of 1 in 876,600 hours, or approximately 0.0001%. From Figure 3.23, by linear extrapolation, the worst-case power fluctuation with this occurrence rate is approximately 65% in one hour, both for positive and negative fluctuations. Therefore the worst-case power fluctuation from multiple wind farms, over one hour, for which system planners should design appears to be 65%.

For look-ahead periods of longer than one hour (Figures 3.24 and 3.25), the worst-case power fluctuation clearly must be assumed to be 100%.

However, Figures 3.23 to 3.25 are based on hourly data, i.e. hourly averages. The results for ten-minute-average data for multiple wind farms are presented in Figure 3.21. This figure shows that, looking one hour ahead, the power fluctuations seen in ten-minute-average data are (not surprisingly) larger than those seen in hourly-average data. Linear extrapolation is more difficult than in Figures 3.23 to 3.25, but an occurrence rate of 0.0001% is seen to correspond with power fluctuations of approximately 90%, both positive and negative.

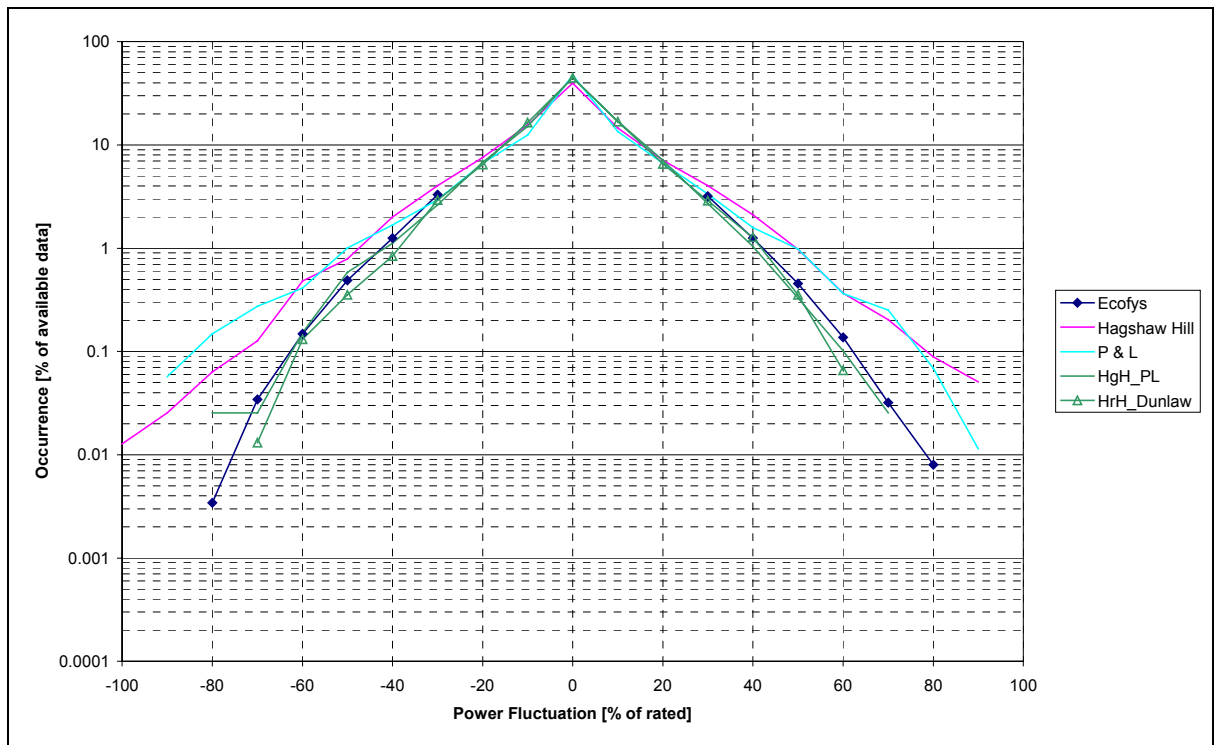
These results are based on pairs of wind farms. Larger groups of wind farms will exhibit smaller net power fluctuations in ten-minute-average data, but long data sets of high-quality ten-minute data from multiple wind farms are not yet readily available for analysis.

In the absence of further data, the analysis presented here allows system planners to make some assessment of the worst-case power fluctuation for which they must plan.

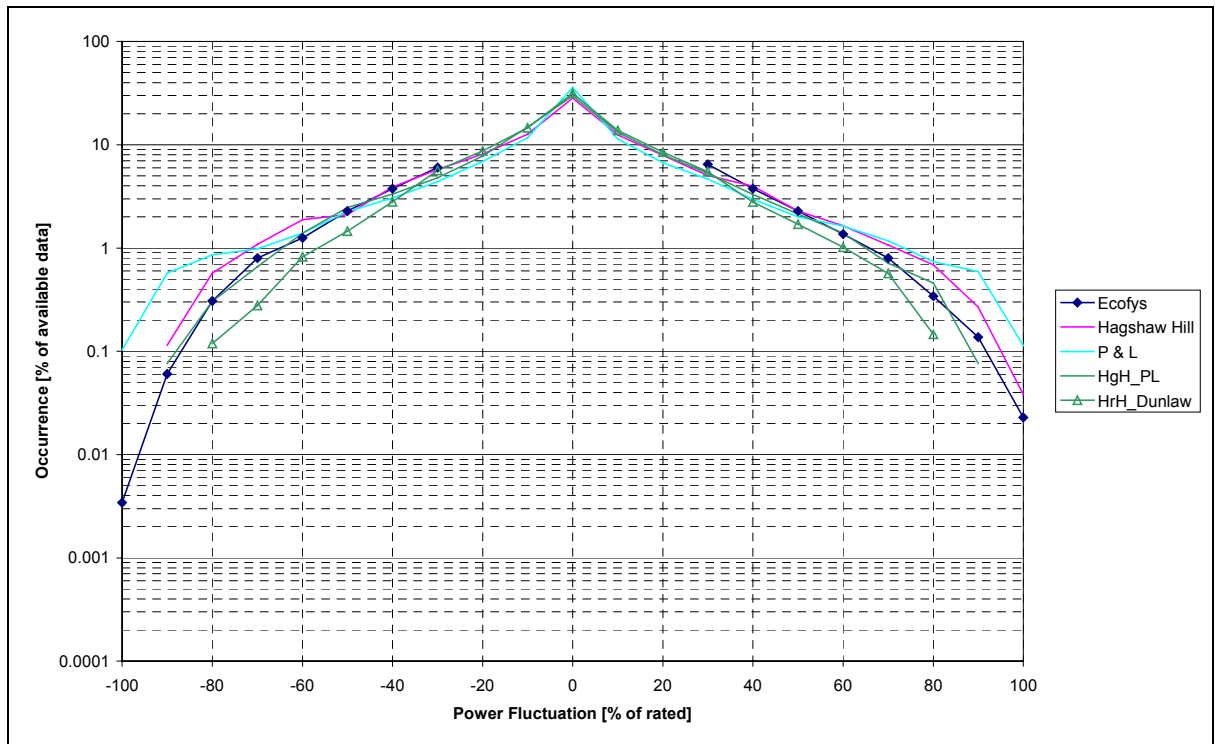


**Figure 3.23** Comparison of all data, averaging period = 1 hour, Tstep = 1





**Figure 3.24** Comparison of all data, averaging period = 1 hour, Tstep = 4



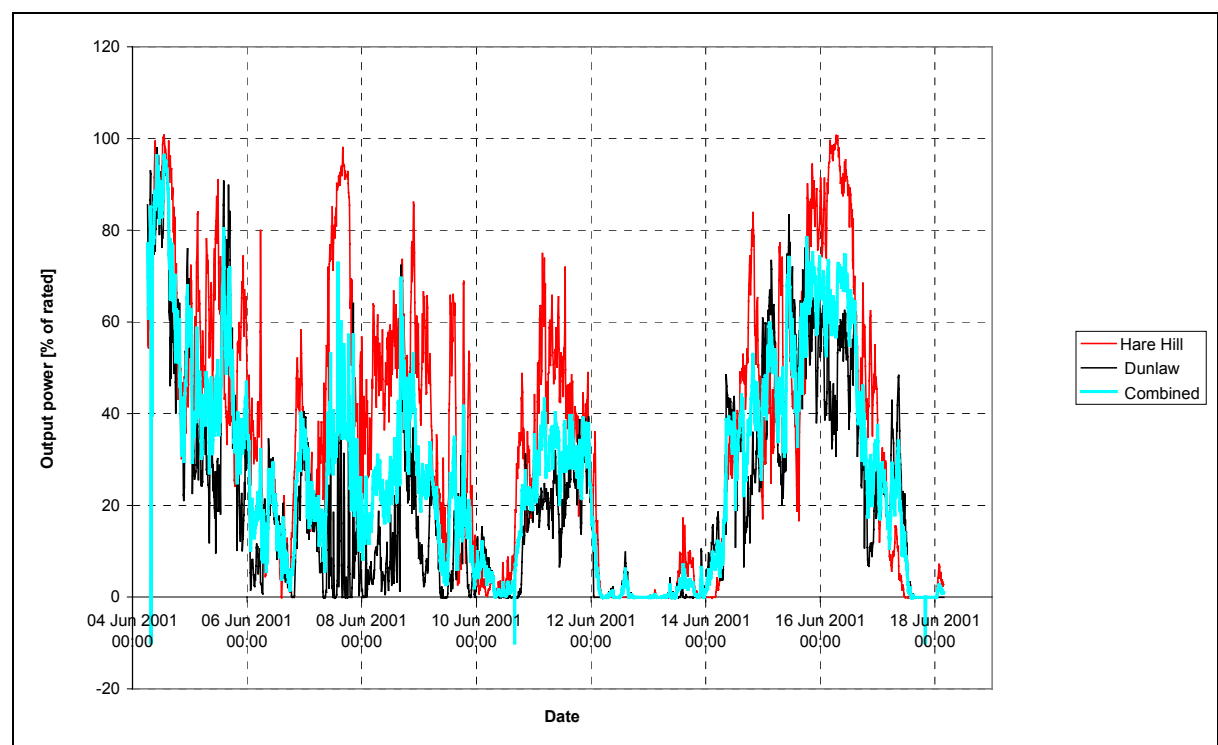
**Figure 3.25** Comparison of all data, averaging period = 1 hour, Tstep = 12

#### 4. FREQUENCY DISTRIBUTION OF POWER PRODUCTION, AND INCIDENCE OF CALMS

The concurrent power output of Hare Hill and Dunlaw was analysed to establish the effect of aggregating output from multiple wind farms, with particular interest in the mitigation of periods of calm (i.e. no or very little wind production). As noted in Section 3, concurrent data from both sites was available for a period of just under one year (Nov 2000 to Sept 2001).

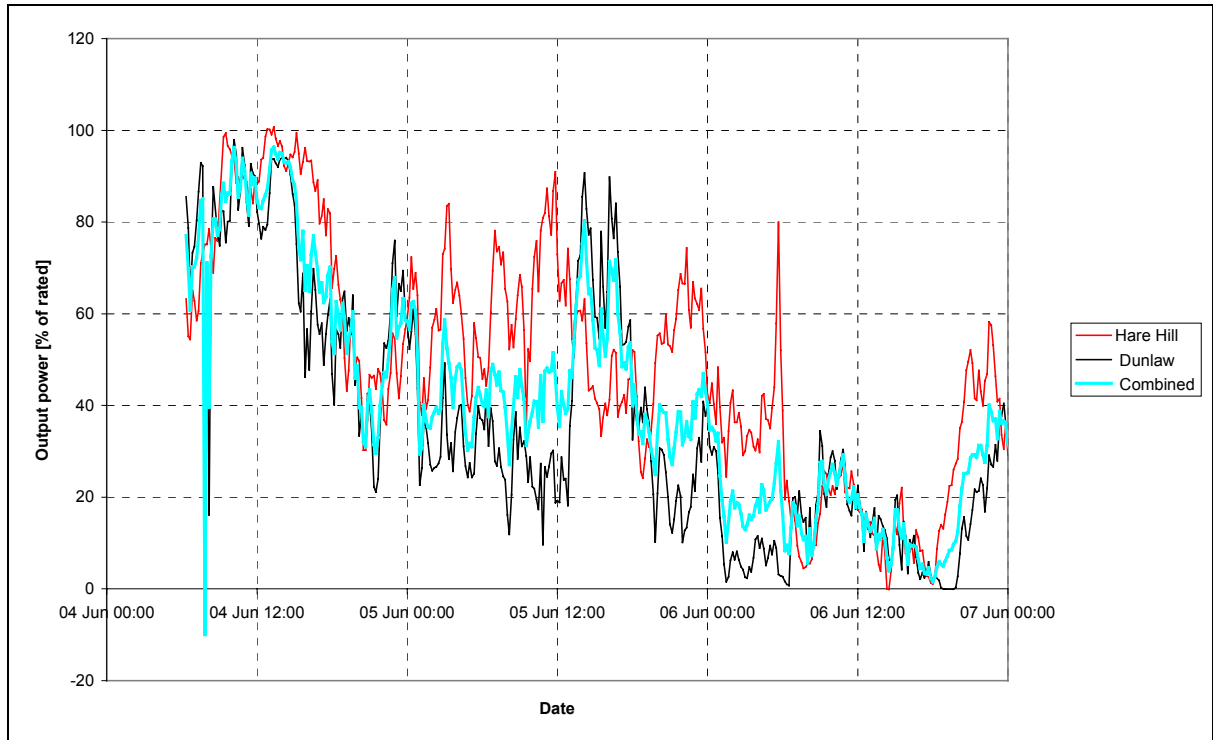
A sample period of 14 days at the start of June 2001 is shown in Figure 4.1. Power output from Hare Hill, Dunlaw and Hare Hill + Dunlaw (i.e. the sum of the two wind farms) is shown as a percent of total rated power. A time history of this limited length clearly does not tell the full story, but several key points can be gleaned:

- Hare Hill operates at a typically greater capacity factor than Dunlaw.
- There are times (e.g. around June 8) when one wind farm is operating at low capacity factor while the other is operating at a relatively high capacity factor. This shows good mitigation.
- There are times (e.g. around June 13) when neither wind farm is generating at all. This shows no mitigation.

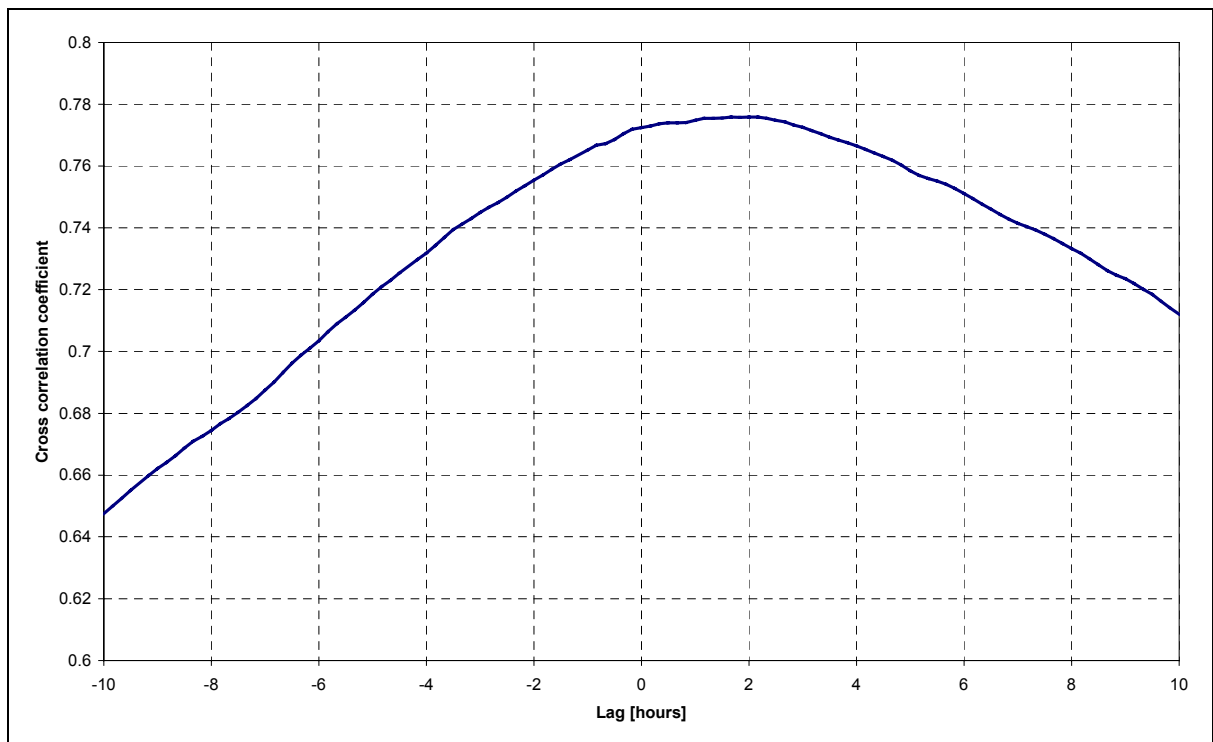


**Figure 4.1** Time series of output power, June 2001

A closer look at the time series shows good mitigation over periods of a couple of hours. Dunlaw is approximately 80 km east-north-east of Hare Hill and, with the majority of our weather passing from west to east, it will tend to see weather events after Hare Hill. This effect can be seen quite clearly in Figure 4.2 where the majority of peaks and troughs occur at Hare Hill an hour or two before they occur at Dunlaw. The one notable exception to this occurring mid-afternoon on June 4, where Hare Hill output declines after Dunlaw's declines. This analysis is further backed up by looking at the cross correlation of the two concurrent time series – this is shown in Figure 4.3 where there is clearly a peak in the correlation coefficient at around 2 hours.



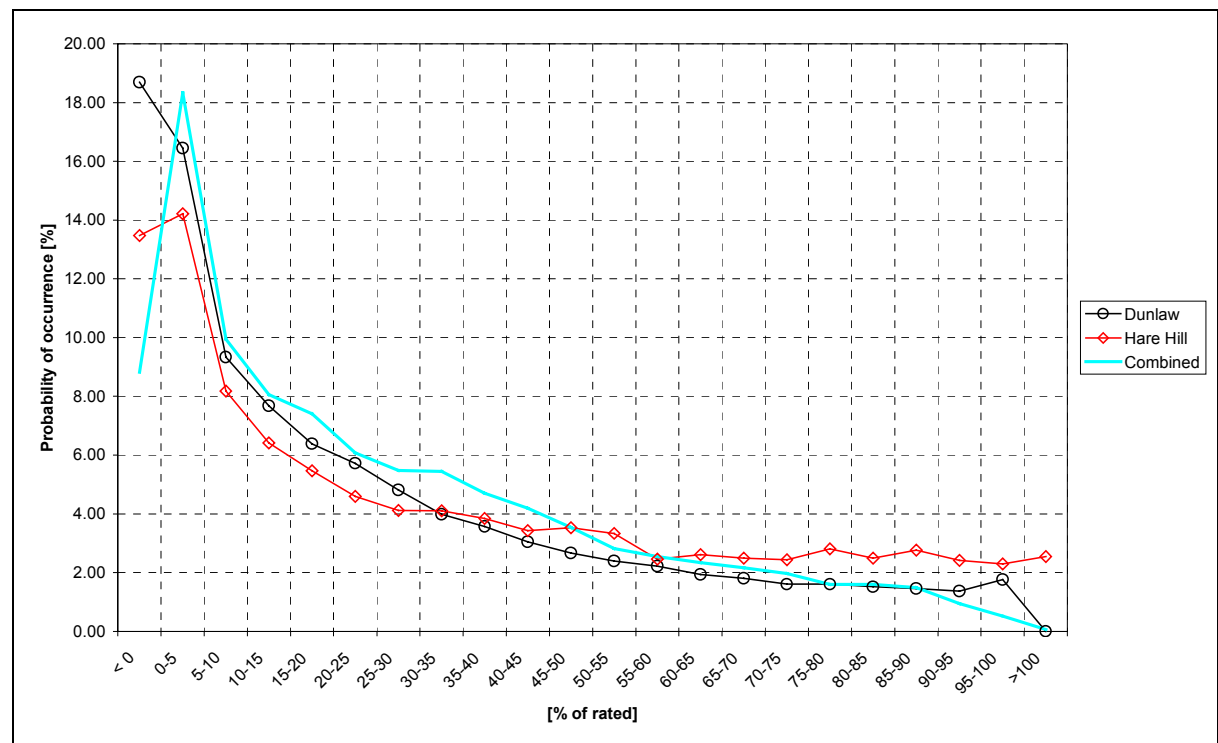
**Figure 4.2 Detailed time series of output power, June 2001**



**Figure 4.3 Cross correlation of Hare Hill and Dunlaw**

It must be borne in mind that this analysis is for a relatively short period (June 2001), when it is likely that the meteorology was dominated by southerly or westerly winds. Although these are the predominant wind directions for the UK and Ireland, there will be significant periods of the year when other conditions prevail, and the correlation shown in Figure 4.3 would not be demonstrated.

The exact effect that this 2-hourly mitigation window has on the power output distributions is shown in Figure 4.4. This figure shows the (normalised) distributions of both wind farms individually, and combined, for the full period for which concurrent data is available (November 2000 to September 2001). Combining the outputs from the two wind farms shows that the occurrence of extreme output levels (i.e. around zero and around rated power) is reduced a little, and the occurrence of mid-range output is increased a little.



**Figure 4.4 Distribution of power output**

The occurrence of calm periods was investigated and compared to previous work [2]. Analysis from [2] shows that single wind farms can expect to produce less than 5 % of rated power for ~50 % of time and that, for aggregated wind farms, this occurrence drops to ~35 %.

Similar analysis for Hare Hill and Dunlaw is presented in Table 4.1. Both Hare Hill and Dunlaw spend considerably less than 50 % of time at less than 5 % of rated power. This is presumably because they encounter generally higher wind speeds than the wind farms studied in [2]. When combined, the time spent at less than 5 % of rated power is less than for either individual wind farm, though the difference from Hare Hill is minimal (27 % of time compared to 28 %).

Wind farm	Time at < 5 % rated output [% of available data]
Hare Hill	28
Dunlaw	35
Combination	27

**Table4.1 Time at < 5 % of rated output**

## 5. SUMMARY

### *Power fluctuations*

This work has provided an insight into the likely occurrence of power fluctuations of wind farm outputs at various sub-hour resolutions (10, 20 and 30 minutes). It has investigated this for single wind farm cases and for combined (dispersed) wind farm cases.

The most extreme negative changes for the short averaging periods may be caused by faults on the distribution network causing the entire wind farm to shut down. This is a cause outside the wind farm's control and is not strictly relevant for this analysis. However it was not possible to eliminate such events from the data.

The data used was from operating wind farms without any attempt to control the power fluctuations. The fluctuations could be controlled in a number of ways:

- Staggered starting, to prevent several turbines starting in a short time. This is achievable by the wind farm SCADA system at no significant cost.
- Staggered shutdown, to prevent several turbines shutting down in high winds in a short time. This is more complex, as it entails either some loss of production or some increased fatigue damage to the turbines, but again is achievable at no significant cost.
- Control of positive ramp rate. Pitch-controlled wind turbines can have the rate of increase of output power limited by the pitch system, either by the wind turbine controller or by the wind farm controller. This entails no significant capital cost. There will be some loss of production, but for the ramp rates currently proposed by system operators it is not thought to be significant.
- Control of negative ramp rate. This requires forecasting, and is discussed in other documents.

From the above it is concluded that the most extreme fluctuations over short timescales (10 to 30 minutes) could be reduced in magnitude and frequency, but it is not clear by how much.

It was also shown that, when the resolution is decreased to 1 hour, the data analysed here for multiple wind farms agree with previous work from Ecofys. Indeed, this work may suggest that the reality is slightly better than predicted by Ecofys (which based analysis on recorded wind speeds rather than recorded wind farm outputs). However, such a conclusion cannot easily be drawn as there are several other factors, which may have influenced this trend. Until further data are available from operating wind farms for concurrent periods of several years, the trends shown in Figures 3.23 to 3.25 may be used.

A further conclusion is that, when system planners and operators are interested in the variation in net power output of multiple wind farms over short periods (up to approximately one hour), then it is important to use data with averaging or sample periods substantially less than one hour, for example ten minutes.

This document also presents a method for estimating the worst-case power fluctuation to be taken into account by system planners. Depending on the probability of occurrence acceptable to the system planners, it appears that for periods of several hours ahead, worst-case power fluctuations of 100% of wind capacity must be expected. The situation for shorter periods ahead (up to say one hour) is not so clear due to the lack of suitable long-term data from multiple wind farms. Of course, such power fluctuations may be foreseen by wind forecasting techniques, and also could be mitigated by the measures discussed above.

#### ***Frequency distribution and incidence of calms***

For multiple wind farms (two in this case) it was shown that the summated power output had fewer periods of very low or very high output, compared to the output of a single wind farm. The incidence of calm periods (less than 5% of rated output) was reduced, but not by as much as in other reported work [2]. This may be because concurrent data was available for only two wind farms.

#### **REFERENCES**

- [1] Coelingh, J.P., "Geographical Dispersion of Wind Power Output in Ireland", (ref. E 60059), Ecofys report for IWEA, Dec 1999.
- [2] van Zuylen, E.J., Ramaekers, L.A.M., van Wijk, A.J.M., Verschelling, J.A. "Wind Power Fluctuations on a National Scale", Proceedings EWEC, Gothenburg, Sweden, pp. 986-989, 1996.

## APPENDIX 5

### Incidence of calms: Met Éireann data

#### Data used

Met Éireann analysed hourly wind speed records for 1981-2000 (20 years) from five met. stations distributed over the island:

- Malin Head
- Belmullet
- Valentia
- Rosslare
- Dublin Airport

The records consisted of wind speed (in knots) at anemometer height (12 to 21 m above ground level), averaged over the ten minutes ending on the hour.

#### Analysis

The analysis counted the number of times the wind speed at all five stations was less than a threshold value. The results are shown in Table A5.1.

Threshold	Number of occurrences in 20 years (175,320 hours)	Occurrences per year
2 kt	1	N/A
4 kt	102	5.1
8 kt	4467	223.4

**Table A5.1: Incidence of calms**

The 8 kt threshold is most relevant. This corresponds to 4.1 m/s at anemometer height. To provide a correction both for height (wind turbine hub height is significantly higher than anemometer height) and for the likely increased exposure of wind farm sites, this threshold can be scaled by the ratio of the annual mean wind speeds at the Met Éireann stations (6.33 m/s average) and the annual mean wind speed for a typical wind farm (assumed to be 8.5 m/s). The 8 kt threshold therefore corresponds to 5.5 m/s on a wind farm site. From analysis of several wind turbine power curves, 5.5 m/s corresponds to approximately 10 % of rated power. The 8 kt threshold therefore corresponds to periods when the wind farm would be producing 10 % of rated output, or less.

It can be seen that the summated output of wind farms dispersed across Ireland can be expected to be below 10% of wind farm rated power for 223.4 hours per year, or 2.5% of the time.

It is important to consider when these events might occur. In particular, the possibility that these periods may coincide with anticyclonic weather in winter (cold clear weather leading to high electricity demand) is of concern.

Table A5.2 shows the distribution of these events by month. There is a clear concentration in the summer, as expected, but still a significant number in the winter months.

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
10.7	4.7	13.3	23.0	16.7	27.0	27.3	37.9	24.5	17.3	13.4	7.8

**Table A5.2: Average hours per month with summated wind farm output less than 10% of rated**

The incidence of calm periods at likely periods of peak system demand in the winter is shown in Table A5.3.

Month	4 pm	5 pm	6 pm	7 pm	Average
November	10	7	9	11	9.3
December	7	5	9	6	6.8
January	7	6	8	7	7.0
February	4	3	6	6	4.8

**Table A5.3: Hours in 20 years when summated wind farm output is less than 10% of rated, during expected periods of system peak demand**

System peak demand will almost certainly occur in December or January between 4 and 7 pm, and it can be seen that for those months there were approximately seven occasions in 20 years when the total wind farm output is expected to be very low at the time of system peak demand. As each month has 31 days, the incidence is seven events out of a possible 620, or 1.1%.

Clearly the hour of peak demand is not the only critical period. From the table above, it can be concluded that the probability of low wind farm output in any of the late afternoon/early evening hours in the winter months is approximately 1.1%. To put it another way, in any one winter it is likely that there will be a total of 5.5 hours of low wind farm output in the late afternoon/early evening period.

### **Comparison with concurrent UK data**

Equivalent data from the UK Met. Office was not analysed as part of this study. However, the periods of low output identified by the Met Éireann analysis were checked against data from operating wind farms, provided by Scottish Power (see Appendix 4).



The aim of this analysis is to determine if low output from wind farms on the island of Ireland is matched by low output from wind farms in Britain. This is important as it determines if support across interconnectors can be expected. The SP data analysed are from Hagshaw Hill (southern Scotland, a prime area for wind developments and close to the Moyle interconnector) and P&L (Wales, relatively close to the eastern end of a possible Dublin-Wales interconnector).

Only one year of data was available (January – December 2000). The results are shown in Table A5.4.

Site	Hagshaw Hill (15.6 MW)	P&L (30.9 MW)	Both sites
<b>Number of records where wind farms on Ireland are producing less than 10% of rated power</b>	361	361	361
<b>No. of valid records in SP data</b>	355	359	353
<b>Average power from GB wind farm</b>	149 kW	513 kW	N/A
<b>Maximum power from GB wind farm</b>	2,542 kW	11,395 kW	N/A
<b>No. of records where output of GB wind farm is less than 10% of rated power.</b>	349 (98%)	343 (96%)	331 (94%)

**Table A5.4: Output of wind farms on Britain when wind farms on Ireland are producing less than 10% of rated power.**

The conclusions are clear. Although there are exceptions (P&L produced over 11 MW during one period of calm in Ireland), in general the GB wind farms are producing very little during calms in Ireland. For 94% of periods where the Irish wind farms are producing less than 10% of rated output, the GB wind farms are also producing less than 10% of rated output.

## APPENDIX 6

### Comparison of transmission system limits with Forecast Statement for 2005

The results shown in Appendix 3 were produced assuming an intact system, on the basis that a single contingency can be coped with by automatically disconnecting wind generation in the area. Current transmission planning criteria require that multiple contingencies are planned for, which will significantly reduce the wind generation capacities found in Appendix 3. This appendix gives, for the ESB National Grid system only, a brief comparison of the results of Appendix 3 with an analysis included in the 'Forecast Statement 2001/2 – 2007/8', produced by the Transmission System Operator Ireland (ESB National Grid at the time of writing), and amended by a modification published in April 2002 (Eirgrid web site).

In order to give guidance to prospective new generators, the Forecast Statement examines the possibility of connecting a new generator of 100 MW capacity at each of 16 110 kV substations, for the system as envisaged in 2004/5. The analysis was done on the basis of the current planning criteria, i.e. including analysis of multiple contingencies.

Unfortunately only five of the substations analysed in the Forecast Statement are included in the 27 substations used in the analysis of Appendix 3, so only limited comparison is possible. The results are shown below.

Substation (110 kV)	Forecast Statement result (2004/5)	Results of this study (2005)
Letterkenny	> 100 MW	180 MW
Sligo	> 100 MW	150 MW
Portlaoise	> 100 MW	400 MW
Tralee	< 100 MW	180 MW
Cahir	> 100 MW	180 MW

**Table A6.1: Comparison of scope for additional generation by two methods**

Note that the Forecast Statement specifically states that the results are not cumulative. In particular, it points out that new generation at Letterkenny would reduce the prospects for new generation at Sligo, and vice versa. In contrast, the results of this study are cumulative, i.e. all the identified generation could be installed together.

There are further differences. This study reduced the conventional generation to take account of the additional wind generation, whereas ESB National Grid state that the Forecast Statement did not assume the output of the existing generation was reduced. The Forecast Statement is based on the time of system minimum demand, whereas this study also looked at the time of system peak demand in order to judge the opportunities if curtailment of wind generation was considered.

It is therefore very difficult to draw any firm conclusions, apart from the obvious conclusion that application of the current planning criteria results in significantly less opportunities for new generation without transmission reinforcement. The case of Tralee would indicate a factor of at least two, but clearly it is unsafe to extrapolate from that to the whole of the ESB National Grid system.

## **APPENDIX 7**

### **Trading Arrangements**

CER is currently reviewing its trading arrangements, and the purpose of this task was to review the relevance of trading arrangements to the success or otherwise of wind energy. A brief, and basic introduction to trading arrangements follows – those familiar with the subject may wish to go straight to the later country-specific sections, which comment on wind energy in selected regimes at various stages of liberalisation.

#### **1 BACKGROUND**

Electricity trading arrangements govern the framework in which commercial transactions take place. They also influence how the system is balanced, and how balancing costs are allocated across participants. There is a world-wide trend for developing “market-based” trading arrangements, the driving force for which is market liberalisation. In turn, the key driving forces for market liberalisation are increased private investment, price reductions and introduction of change.

Market liberalisation often involves both changes to the industry structure and changes to electricity trading arrangements. The effects of each are often difficult to distinguish.

Changes to industry structure involve, mainly, separation of monopoly from competitive activities and divestment of assets. Changes to electricity trading arrangements can be relatively simple mechanisms to allow new market entry – these allow new entrants to access top-up and spill, provide a means whereby independent trades are commercially settled and a mechanism for accounting for, and controlling, independent trades when balancing the system. More sophisticated arrangements are increasingly being introduced in a drive towards economists’ more “perfect” markets, the rationale for which is variously price reductions, and fair and competitive markets.

There are significant costs to these changes – for instance, in making market participants more accountable for their actions, it is necessary to monitor their actions through metering and communications. A whole new industry centred on trading electricity is created, and regulatory costs are also incurred. Inevitably, market developments must take account of the physical characteristics of the electricity system, the laws of physics, cost, practicality and politics. For instance it is not practical, cost-effective or politically attractive to require every domestic customer to install half hourly metering.

Wind energy, a relatively new technology in the mainstream electricity supply industry, has experienced both gains and losses under these developments. It has generally benefited from measures to facilitate new entrants. It has also benefited from a culture of change in the industry, as wind energy’s introduction necessitates changes in a number of activities such as system operation and grid connection.

Wind energy has arguably suffered from trading arrangements which incentivise characteristics which it does not possess – either because of currently cost-effective wind turbine design, or because of fundamental technical limitations. Most talked about of these are market penalties for not meeting forecasted output.

The question therefore for an administration, is to what degree, and in what way, it develops its trading arrangements given present and anticipated future technology mixes. Although theoretically technology and participant neutral, practicalities and cost will always limit the

degree to which this is achievable. Cost allocations will always be approximate and rarely consider “externalities”, and furthermore cost allocations only reduce total costs if they successfully incentivise a reduction in costs.

If an administration takes as granted that it wishes to see wind energy increase its market share (which is reflected in many government support mechanisms, and is often seen as a means to address market failure in internalising all costs), it may also wish to ensure that its trading arrangements do not either act against this, or increase costs of its wind energy policy implementation.

To inform the debate on trading arrangements in the Republic of Ireland and Northern Ireland, and specifically, wind energy’s participation, the following sections review experience of wind energy in liberalised markets. The situation in the Republic and Northern Ireland is reviewed, as is some experience abroad where there is a sizeable amount of wind on the system, exposed to liberalised market arrangements.

## **2 REPUBLIC OF IRELAND**

### **2.1 Industry Structure**

The Electricity Supply Board (ESB) is a state-owned, vertically integrated utility with generation, transmission, distribution and supply businesses. ESB National Grid currently acts as Transmission System Operator (TSO) and Settlement System Administrator (SSA), but this role is being transferred to a wholly independent company, Eirgrid. TSO functions encompass operation, maintenance, connection to and development of the transmission system, generation scheduling and dispatching, and for ensuring system security. Ownership of the transmission system will remain with ESB. ESB Independent Energy is a subsidiary of ESB which was formed to supply the sector of the Irish market which is open to full competition (see below).

The Irish market is mid-way through a process of progressive market opening, with an ultimate aim of full market opening by 2005. At present, ESB has near-monopoly access to the franchise sector, which represents 60% of the market. Competition has been introduced for the other 40% – approximately 1,600 customers with an annual demand of at least 1GWh. The exception to this is dedicated green suppliers (renewables and CHP), who are granted full market access. In excess of 19,000 customers are presently supplied by green suppliers.

Ireland has some of the lowest domestic electricity prices in Europe. Prices for commercial customers are however often quoted as being relatively high to support this. This is important in determining Ireland’s rationale for liberalisation.

### **2.2 Trading arrangements**

CER regulates the market, and has overseen the introduction of arrangements which facilitate trade within the independent sector and between independent parties and ESB. A set of transitional trading arrangements are in place, with ongoing modifications, until 2004, by when more fundamental review is planned.

The present market was intended to, and is structured to operate as, a bilateral contracts market in conjunction with an imbalances market to deal with mismatches between contracted and actual generation and/or contracted supply and actual load.

The transitional trading arrangements constitute, very briefly, a trading code to which the majority of participants must accede, a balancing mechanism that includes a system of top-up and spill with regulated prices, and a settlement system. Top-up and spill prices become more penal beyond tolerance levels set for suppliers and generators. Because wholesale energy is not readily available to independent suppliers, CER has also mandated an auction of 600MW of ESB generation, such that it is available to independents – termed “virtual” generation.

Trading is carried out in half-hourly periods. Generators subject to central dispatch nominate proposed generation output to the TSO a day ahead, together with bids for incremental increases and decreases. The TSO bases its provisional running order on these nominations. Deviations from nominations may be necessary to resolve system security constraints or to match the demand for and supply of energy in real time. Deviations from nominations will be made by the TSO on the basis of generator price bids for incremental or decremental changes to nominations. The TSO has a duty to dispatch the system at least cost.

Imbalances incurred by the generators arising from differences between the TSO’s dispatch instruction and the units’ output will be cleared at the top-up or the spill price. These are termed ‘*uninstructed imbalances*’.

Energy market imbalances occur in each half hour trading period when the final contracted volumes of electricity differ from actual generation and metered load. These final contractual positions can be notified to settlements up to 7 days after the trading period, thus allowing participants to trade imbalances between themselves.

Following this 7 day period, ESB Power Generation (PG) sells a limited amount of electricity at top-up prices, in order for participants to meet ‘shortfalls’. Top-up prices are published for the year ahead and are referenced to the estimated average annual cost of the Best New Entrant (BNE) into the market. ESB PG also purchase ‘excess’ generation at spill prices. A first tranche of spill (25% of eligible customer demand) is related to ESB’s avoided fuel cost, the remaining tranche the BNE avoided fuel costs. Top-up prices are known in advance, spill not until after the event.

## **2.3 Wind energy participation**

Independent wind energy plant are exposed to the trading regime, but enjoy a number of advantages in the liberalised market.

Green electricity suppliers have access to 100% of the market base, whereas non-green suppliers have access currently to only 40% of the market. By virtue of the size of wind turbines, wind generated electricity is currently not subject to central dispatch. All generating units (i.e. individual wind turbines as opposed to wind farms) less than 5 MW currently self-dispatch. This is a distinct advantage to wind energy as it is not exposed to uninstructed imbalances, which could be significant due to the difficulties in wind energy prediction – this is currently under review by CER, and replacing this with priority dispatch coupled with compensation is under consideration.

Green suppliers may purchase top-up to meet all their requirements in a given trading period. However a green supplier is required to balance (subject to an allowable 5% error margin) top-up and/or bilateral contract purchases of non-green electricity with green energy purchases (bilateral contracts, imports and/or generation), which are spilled.

In practice however, there are very few wind farms that are not fully contracted to ESB Public Electricity Supply (PES) through an AER contract. There are some 39 MW of operational wind generating capacity currently supplying customers in the liberalised market, with a

further 25 MW under construction. This is augmented by some 25 MW imported from Northern Ireland and further additional imported electricity from Scotland.

To facilitate green energy supply at the early stages of market opening, CER held a separate auction for 40GWh of green electricity (equivalent approximately to the output of a 12 MW wind farm).

Green supplies to non-eligible customers below a certain threshold are settled on the basis of profiles, which avoids the need for half hourly metering of these customers, and avoids the expense of suppliers instigating profiling for a relatively small pool of customers.

### **3 NORTHERN IRELAND**

#### **3.1 Industry structure**

Northern Ireland Electricity (NIE) is a privatised utility with transmission and distribution, power procurement and supply businesses. NIE Supply is at present the near monopoly supplier in the franchise sector of the market, which is not yet open to wholesale competition. Four second tier suppliers (STs) are currently active in the eligible market, which is open to competition and constitutes 35% of the market with a customer qualification threshold of 0.79GWh.

NIE's holding company, Viridian, has generation interests in the Republic of Ireland. All generation in Northern Ireland is independent, but fully contracted to NIE's Power Procurement Business (PPB). The majority of generation is contracted to PPB in long-term power purchase contracts which include a capacity as well as an energy payment. The terms of these contracts are, in retrospect, relatively generous and there has been some renegotiation. Nonetheless, generation costs, and hence electricity prices, are relatively high in Northern Ireland.

Theoretically, independent suppliers can access the franchise market, but they must make purchases from NIE at the Bulk Supply Tariff (BST), which effectively has constrained competition in this sector. The exception to this is renewables suppliers, who can supply the franchise market with independent energy purchases.

#### **3.2 Trading Arrangements**

Wholesale energy is available to STs in the eligible market, through purchase from PPB at NIE's BST, through the Moyle Equivalent Energy and Non Fossil Fuel auctions, or from external sources with secured capacity on the interconnectors.

Independent trades are settled in half hourly blocks on the basis of ex ante (before the event) notified contract positions. The PPB also provides top-up at the BST price, and purchases spill at the avoided system marginal cost. Any revenues earned by PPB in purchasing spill which is re-sold as top-up are used to reduce the BST. Generation sold to NIE, and purchases made wholly from NIE at the BST, are not subject to the top-up and spill regime.

#### **3.3 Wind energy participation**

Currently, all existing large-scale wind plant in NI is contracted to NIE PPB under the NI Non Fossil Fuel Obligations I and II. The output-equivalent of the 40 MW of NI-NFFO capacity is auctioned into the eligible market, enabling the non-domestic sector of this market to

benefit from the Climate Change Levy. The energy is mainly traded in Northern Ireland or exported to the Republic. There are also a number of independent projects proposed in Northern Ireland, 47 MW of which is currently under construction.

In recognition of the difficulties, principally in balancing, that renewables face in the conventional regime, Ofreg convened the “Trading in Renewables Implementation Group” (TRIG), in 2001. A consultation paper was issued in 2001, which, on wind energy, stated that “wind energy is the primary near-market priced large scale renewable resource in Northern Ireland. In order to make the trading system more accommodating to the intermittent nature of the technology, modifications will be required.”

After consideration of responses, Ofreg implemented the Renewable Output Factor (ROF) trading arrangements for wind power in November 2002, to encourage trading in the NI market for renewable energy, which is 100% open to competition. ROF offers suppliers of intermittent generation an alternative to the half-hourly balancing system applicable to independent conventional generation. Under ROF, a renewable supplier is required to procure 120% of the energy required to meet its customer’s demands. The extra 20% of energy put on the system serves to compensate PPB for bearing the risks of the ROF arrangements. Balancing occurs on an annual basis, with a 10% carry-over imbalance allowance on this figure. Additional imbalances are settled with shortfalls purchased from the PPB stock of renewables at BST and excess production sold to PPB at its “renewable purchase price.”

## **4 ENGLAND AND WALES**

### **4.1 Industry structure**

Electricity privatisation in England and Wales (E&W) created one transmission owner and operator – National Grid Company (NGC) – twelve regional distribution and supply companies – Regional Electricity Companies – and two generators – National Power and Powergen. Subsequent development has seen divestment of plant by the generating companies and increasingly stringent controls on ring-fencing of activities for companies which undertake both monopoly and competitive activities. At the same time, there has been considerable consolidation in the industry through acquisitions by either foreign, or one of the two Scottish vertically integrated, companies. The market remains in flux, with for instance the recent acquisition of the UK TXU supply business by Powergen (in turn owned by E.ON) and the merger of NGC and Lattice.

### **4.2 Trading Arrangements**

The last year and a half has seen significant change in electricity trading arrangements in E&W with the introduction of the New Electricity Trading Arrangements (NETA). Replacing the electricity pool, NETA “*was designed to deliver more competitive market-based trading arrangements*” [30]. Under NETA, bulk electricity is traded in forwards markets through bilateral contracts and Power Exchanges. Contractual positions for each half hour must be notified at the latest at “gate closure”, which is latterly one hour ahead of the start of each half hour trading block (until recently, gate closure was 3.5 hours ahead of real time). Deviations from notified and metered positions are cashed out in a dual price mechanism where prices are derived from the balancing costs incurred by NGC.

NETA provides the “central mechanisms” for balancing and settlement, with other functions, including power exchange and consolidations services, left to the market. These central

mechanisms are a short-term balancing market run by NGC, the settlement system and various governance functions.

### **4.3 Wind energy participation**

Wind energy participates in the market in so far as its output is traded just as any other. However, most if not all wind energy generators do not directly participate in trading, instead contracting with a party which will subsume the output into its portfolio.

When NETA was under development, wind energy proponents counselled against ex ante notification and dual cash out prices (at least their applicability to wind energy), which they considered were unnecessarily penal to intermittent and/or small generators. A number of ameliorative arrangements were discussed at this stage, which would be available to “small” generators. Some of these were implemented, most notably a benefit formerly available through the old pool which allows embedded plant to be treated as negative demand – under NETA, “licence exempt” plant can be treated as negative demand, and thus netted off against demand (this is an exception to the rule that requires separate settlement of production and consumption accounts). Most if not all existing wind energy plant is traded in this way.

However the renewables and small generator bodies remained sceptical on their costs under NETA, and Ofgem agreed to review the performance of “small” generators under NETA. The results of a 1 year review, based on a generator questionnaire, concluded no significant detriment to small generators in terms of output and revenue, when set against the general industry trends. Amongst the technologies considered, CHP does appear to be faring poorly. Ofgem also recognised, and undertook to address, the lack of any useable consolidation services for small generators.

Ofgem’s findings for wind energy generators appear to reflect the improved market prospects under the new Renewables Obligation, and the prices commanded for ROCs in a short-supply market. If the value of ROCs were discounted, the picture would certainly be different. Thus the key question is if wind energy’s full exposure to NETA is an efficient way in which to deliver the Obligation. It is notable that technologies not eligible under the Obligation have fared the worst. Furthermore, as larger intermittent plant such as offshore wind are developed, they can be expected to suffer more under NETA as they will not benefit to the same extent, if at all, from current concessions aimed at small generators.

Small and intermittent generator groups continue to push for changes to NETA, which are better suited to the characteristics of these plant. A modification currently under assessment proposes a short-term interim solution of a single cash out price.

## **5 CALIFORNIA**

### **5.1 Industry structure**

Industry restructuring in 1996 created the California Independent System Operator (CAISO) and the California Power Exchange (CalPX). CAISO combines the system operation functions previously undertaken by three vertically integrated, investor-owned utilities (IOU’s) – Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). The three utilities for the most part remain owners of the transmission lines. For a transitional period to April 2002, generation arms of the IOU’s were required to sell power into the CalPX, a requirement which was terminated early following the Californian electricity crisis and the ultimate demise of the CalPX. There is a widely-held



belief that the Californian problems were at least in part due to an over-reliance on spot markets.

## **5.2 Trading Arrangements**

Still somewhat in a state of flux in the wake of market disruptions, there are several key features of the market which can be identified.

CAISO operates markets for congestion management, real time balancing and ancillary services. “Scheduling co-ordinators” submit energy forecasts a day ahead and 2-2.5 hours ahead of real time. Energy schedules are for one hour periods – that is, for any one hour in real time, the last chance (effectively) to confirm positions is 2.5 hours ahead of that hour, which is called the hour-ahead market. Settlement of positions is in 10 minute blocks, with dual cash-out prices for under and over production.

## **5.3 Wind energy participation**

The majority of wind energy facilities in California benefit from favourable purchasing status whereby utilities are mandated to purchase the output of “Qualifying Facilities” at an agreed avoided cost, made up of a capacity and energy element. This has to date shielded plant from direct participation in the open market.

Latterly, uncertainties in the future price for QF’s has led some generators to consider selling direct into the market. However, the trading arrangements, particularly the need for accurate forecasting and dual cash out, 10 minute settlement, are not suited to the characteristics of wind energy. In recognition of this, CAISO set up the “Intermittent Resources Working Group”, on which industry, regulatory and voluntary interests are represented. This has culminated in an agreed market arrangement, whereby participating intermittent resources implement CAISO’s own forecasting system, and are cashed out against their averaged monthly deviations from submitted schedules. Basic principles for the forecasting tool were agreed through the working group, and used as a basis for inviting tenders to supply the forecasting service. This new system has only just been implemented, and CAISO must report performance to the Federal regulator in 16 months.

## **6 AUSTRALIA**

Only a very brief description of the Australian situation is included here.

Australia is experiencing a relatively recent, but expanding, market for wind energy, and its electricity markets are at various degrees of liberalisation. Australia has four separate electricity markets – the National Electricity Market (NEM) in the South and East; Western Australia; Tasmania; and Northern Territory. Wind energy is being developed in the first two of these.

The NEM is based on a mandatory pool into which most generators must bid, and from which most purchasers must buy. Day ahead bids in 5 minute intervals are submitted to the pool, with the chance to re-bid up to 5 minutes before each interval. Despatch instructions are based on the 5 minute interval bids. Spot prices are derived from the average marginal bid price across a half hour. Wind energy (as well as other small generators) does not at present bid into the pool.

There is no real open market in Western Australia, but reforms are planned. Initial proposals from the “Electricity Reform Task Force” envisage a wholesale market based on bilateral contracts, with a Residual Trading Market (RTM) and mechanisms for balancing and congestion management. Principles for participation of renewables are stated as there being *“no restrictions on, or penalties for, out of balance renewables; re-bidding in the RTM should be as close to real-time as practicable for operational purposes; and, in rebidding, non-despatchable renewable generators should not be limited when changing original bids in the RTM.”*

## **7 SUMMARY**

On the basis of the very limited experience reviewed here, the following observations can be made:

- Liberalisation appears to have been designed for participation of, and reduction of costs in, the conventional (present) generation sector.
- A range of fixes have been adopted which variously seek to accommodate, or actively encourage participation of, non-conventional generators: NETA in England and Wales, and the markets in Australia, have focused on accommodating small generators; Ireland focuses on encouraging participating of competing green electricity suppliers; Northern Ireland has focused on accommodating wind energy; California has focused on encouraging the participation of wind energy. There is no one model of proven success.
- Differences probably reflect the driving force for liberalisation, whether a market is in transition, the predominant size of wind energy projects and the outlook of the Regulator.
- With the possible exception of NETA, Regulators appear to have taken a “common sense” approach to anticipated difficulties, rather than applying rigorous economic tests. In the case of NETA, the Regulator’s interpretation of his duties, the desire for a “pure” solution, and an overwhelming workload at the time of NETA’s implementation, may have been key in determining the present situation.

## **8 REFERENCES AND FURTHER INFORMATION**

Key references employed in compiling this section, and sources of further information for the more interested reader, are listed below, categorised by country. Additional information was also kindly provided by CER and Ofreg.

### **Republic of Ireland**

- [1] IPA Energy Consulting, PB Power, Energy Links Consultancy. April 2001. “Describing Republic of Ireland and Northern Ireland Energy Markets and Identifying Barriers to Trade.” Interim Report Volume 1. For the Northern Ireland Department of Enterprise, Trade and Investment and the Republic of Ireland Department of Public Enterprise.
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## **England and Wales**

- [9] Ofgem, July 2002. "The Review of the First Year of NETA." A Review Document. Volumes 1 and 2.
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## **Australia**

- [13] Commonwealth of Australia, 2002. "Towards a Truly National and Efficient Energy Market."
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